COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATE FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE CANE RUN GENERATING STATION AND THE PURCHASE OF EXISTING SIMPLE CYCLE COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC IN LAGRANGE, KENTUCKY	)	CASE NO. 2011-000375

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the hearing conducted on March 20, 2012 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the hearing conducted on March 20, 2012 in this proceeding;

- The written log listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recording of the hearing conducted on March 20, 2012.

A copy of this Notice, the certification of the digital video record, exhibit list, and hearing log have been served by first class mail upon all persons listed at the end of this Notice. Parties desiring an electronic copy of the digital video recording of the hearing in

Windows Media format may download a copy at http://psc.ky.gov/av_broadcast/2011-00375/2011-00375_20Mar12_Inter.asx. Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

The exhibits introduced at the evidentiary hearing may be downloaded at http://psc.ky.gov/pscscf/2011%20cases/2011-00375/.

Done at Frankfort, Kentucky, this 3rd day of April 2012.

Linda Faulkner

Linda Faulkner
Director, Filings Division
Public Service Commission of Kentucky

Honorable Joe F Childers
Attorney at Law
201 West Short Street
Suite 310
Lexington, KENTUCKY 40507

Lawrence W Cook
Assistant Attorney General
Office of the Attorney General
Utility & Rate Intervention Division
1024 Capital Center Drive
Suite 200
Frankfort, KENTUCKY 40601-8204

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CALIFORNIA 94105

Honorable Lindsey W Ingram, III
Attorney at Law
STOLL KEENON OGDEN PLLC
300 West Vine Street
Suite 2100
Lexington, KENTUCKY 40507-1801

Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

Honorable Kendrick R Riggs
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KENTUCKY 40202-2828

Honorable Allyson K Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

Edward George Zuger, III
Zuger Law Office PLLC
P.O. Box 728
Corbin, KENTUCKY 40702

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATE FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION	) CASE NO. 2011-00375

CERTIFICATE

I, Kathy Gillum, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on March 20, 2012; (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of March 20, 2012 (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of March 20, 2012 (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of March 20, 2012 (excluding any confidential segments) and the time at which each occurred.

Given this 3rd day of April, 2012.

Kathy Gillum

Kathy Gillum, Notary Public
State at Large

My commission expires: Sept 3, 2013

Case History Log Report

Case Number: 2011-00375_20Mar12

Case Title: Louisville Gas & Electric Company and Kentucky Utilities Company
Case Type: Other
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Date: 3/20/2012
Location: Default Location
Judge: David Armstrong, Jim Gardner
Clerk: Kathy Gillum
Bailiff:

Event Time	Log Event	
10:05:33 AM	Case Started	
10:05:40 AM	Preliminary Remarks	
10:05:56 AM	Introductions	
	Note: Kathy Gillum	Lindsey Ingram, III, Allyson Sturgeon and Duncan Crosby, III for LG&E and KU; for the Intervenors (SC\NRDC), Joe Childers,
10:06:45 AM	Joe Childers (SC\NRDC)	
	Note: Kathy Gillum	Mr. Childers states they have a Procedural Motion. Moves that Shannon Fisk can appear on behalf of NRDC and Sierra Club.
10:07:31 AM	Quang Nguyen (PSC)	
	Note: Kathy Gillum	No objection.
10:07:41 AM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	So Ordered.
10:07:51 AM	Introductions	
	Note: Kathy Gillum	Kurt Boehm for KIUC; For the Attorney General, Larry Cook; and for the Sierra Club, Shannon Fisk and Kristin Henry
10:08:27 AM	Public Notice	
	Note: Kathy Gillum	Public Notice has been done except for one publication by KU in Flemingsburg. A Motion for Deviation is before the Commission. No Objections voiced. Chairman granted request. No other Motions.
10:09:51 AM	Public Comments	
	Note: Kathy Gillum	Only one member of the public present, states she was just observing.
10:11:02 AM	Witness, Paul Thompson (LG&E-KU)	
	Note: Kathy Gillum	Witness called to testify by Lindsey Ingram on behalf of LG&E-KU.
10:11:45 AM	Qualification of Witness by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Witness adopts pre-filed testimony.
10:12:30 AM	Examination by Quang Nguyen (PSC)	
	Note: Kathy Gillum	Questions regarding Direct Testimony, page 7.
10:13:22 AM	Paul Thompson (LG&E-KU)	
	Note: Kathy Gillum	Witness states there is no plan to use other existing coal fired facilities.

10:14:30 AM	Examination by Quang Nguyen (PSC) continues	
	Note: Kathy Gillum .	Questions regarding the Ash pond at Cane Run. Questions regarding Supplemental Response, Item 3. Questions regarding the number of employees. Questions regarding informal committments of non-union staff.
10:21:06 AM	Vice-Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding Page 4, Line 21.
10:21:42 AM	Paul Thompson (LG&E-KU)	
	Note: Kathy Gillum	Witness explains the term "cost effective".
10:23:22 AM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding relationship with PPL and EON regarding DSM programs.
10:24:16 AM	Paul Thompson (LG&E-KU)	
	Note: Kathy Gillum	Witness states that the management has not instructed them to do anything differently than they had been doing.
10:26:04 AM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Question: What are the advantages of membership with PPL and EON regarding DSM Programs?.
10:26:54 AM	Paul Thompson (LG&E-KU)	
10:27:27 AM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Questions regarding public relations or processes during the re-build.
10:28:13 AM	Paul Thompson (LG&E-KU)	
	Note: Kathy Gillum	States that they will keep the community aware duriing the re-build.
10:30:50 AM	Witness Excused (Thompson)	
	Note: Kathy Gillum	
10:31:01 AM	Witness, John Voyles (LG&E-KU)	
	Note: Kathy Gillum	Witness called to testify by Lindsey Ingram on behalf of LG&E-KU.
10:31:41 AM	Qualification of witness by Duncan Crosby	
	Note: Kathy Gillum	Witness adopts pre-filed testimony and responses to data requests.
10:32:30 AM	Examination by Joe Childers (SC\NRDC)	
	Note: Kathy Gillum	Questions regarding replacement life of the machine.
10:33:17 AM	John Voyles (LG&E-KU)	
10:33:27 AM	Examination by Quang Nguyen (PSC)	
	Note: Kathy Gillum	Questions regarding page 4 of Direct Testimony.
10:34:06 AM	John Voyles (LG&E-KU)	
	Note: Kathy Gillum	Witness states that the SPP study has not been concluded to date. States that a feasibly study has been looked at.
10:35:53 AM	Examination by Quang Nguyen (PSC) continues	
	Note: Kathy Gillum	Questions regarding page 6 of Direct Testimony.
10:36:14 AM	John Voyles (LG&E-KU)	
	Note: Kathy Gillum	Witness answers: Short list by April or May.
10:37:58 AM	Examination by Quang Nguyen (PSC) continues	
	Note: Kathy Gillum	Questions regarding page 12.
10:38:34 AM	John Voyles (LG&E-KU)	
10:39:03 AM	Examination by Quang Nguyen (PSC) continues	
	Note: Kathy Gillum	Questions regarding 2nd DR, Item 3. Questions regarding transmission upgrades.
10:43:10 AM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding 2nd DR Item 2.
10:46:08 AM	John Voyles (LG&E-KU)	

10:46:37 AM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding Item 3.
10:47:19 AM	John Voyles (LG&E-KU)	
10:48:10 AM	Witness Excused (Voyles)	
10:48:27 AM	Witness, Gary Revlett (LG&E-KU)	
	Note: Kathy Gillum	Witness called to testify by Lindsey Ingram on behalf of LG&E-KU.
10:49:01 AM	Qualification of witness by Duncan Crosby (LG&E-KU)	
	Note: Kathy Gillum	Witness adopts pre-filed testimony and responses to data requests.
10:50:19 AM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding environmental benefits. MGCC technology regarding acid gases.
10:51:28 AM	Gary Revlett (LG&E-KU)	
	Note: Kathy Gillum	Witness states that there is almost no mercury in natural gas.
10:53:07 AM	Witness Excused (Revlett)	
10:53:24 AM	Witness David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness called to testify by Lindsey Ingram on behalf of LG&E-KU)
10:54:00 AM	Qualification of witness by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Witness adopts pre-filed testimony and data responses with corrections. Exhibit 1 of Joint Applicants.
10:55:27 AM	Exhibit LG&E-KU 1	
	Note: Kathy Gillum	Exhibit: 3 documents with yellow highlighted information to be used as corrections to pre-filed testimony and responses to data requests previously filed. Documents introduced by Lindsey Ingram and marked as LG&E-KU Exhibit 1. (Stated that page numbered 5 is relating to sales and energy requirements. The changes to the 3rd document marked in yellow, is in relation to question No. 8 of PSC Data Requests.)
10:58:55 AM	Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Moves to admit the 3 documents as LG&E-KU Exhibit 1.
10:59:11 AM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	So ordered. (There were no objections)
10:59:41 AM	Examination by Joe Childers (SC\NRDC)	
	Note: Kathy Gillum	Questions regarding controls that need to be installed.
11:02:56 AM	David Sinclair (LG&E-KU)	
11:04:02 AM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding additional controls that would be needed.
11:05:54 AM	Examination by Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Questions regarding the controls.
11:07:11 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states that the data used in the analysis was in the Spring of 2011. Witness explains the RFP process.
11:10:46 AM	Exhibit SC\NRDC 1	
	Note: Kathy Gillum	Exhibit: Letter dated December 17, 2010 from LG&E-KU regarding Request for Proposals to Sell Capacity and Energy (RFP)
11:12:14 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC\NRDC Exhibit 1.
11:13:38 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness testifies regarding uncertainties.
11:18:18 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Page 16 of Rebuttal Testimony.

11:19:49 AM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk states that the Exhibit was attached to Resource Assessment. Moves to admit as Exhibit. No Objections.
11:20:47 AM	Exhibit SC\NRDC 2	
	Note: Kathy Gillum	Exhibit: Excerpts from 2011 IRP. Document titled, "State of South Carolina, Docket Number 2011-10-E, Duke Energy Carolinas, LLC's 2011 Intregrated Resource Plan (IRP). Exhibit introduced by Mr. Fisk and marked as SC-NRDC Exhibit 2.
11:22:01 AM	Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Mr. Ingram asks Mr. Fisk to explain the omission of the middle pages of the document.
11:22:56 AM	Shannon Fisk (SC\NRDC)	
11:23:00 AM	Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Mr. Ingram requests to be allowed to revise any answers given by the witness to the incomplete document.
11:24:11 AM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman stated that he was going to allow the request.
11:24:49 AM	Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook points out that this is Duke Energy Carolinas.
11:25:14 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Page 100-101 of SC\NRDC Exhibit 2.
11:26:13 AM	Objection by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Mr. Ingram objects that the witness cannot answer due to not having the entire document.
11:27:05 AM	Objection by Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook objects stating that too much is missing.
11:27:25 AM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk states: Duke Energy is assuming CO2 prices.
11:28:29 AM	David Sinclair (LG&E-KU)	
11:31:38 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Question: How long is the expected operating life of the plant. Questions regarding CO2 emissions of wind power.
11:32:01 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states that the wind doesn't always blow when a customer needs generation.
11:38:06 AM	Shannon Fisk (SC\NRDC) and Lindsey Ingram Objection	
	Note: Kathy Gillum	Mr. Fisk moves to admit Exhibit 2 into evidence. Lindsey makes same objection as before. Chairman accepts the Exhibit with caveat.
11:39:06 AM	Exhibit SC\NRDC 3	
	Note: Kathy Gillum	Exhibit: Excerpts from Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2. Document titled, "Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 ..., Docket No. 34218 dated August 4, 2011. Exhibit introduced by Mr. Fisk and marked as SC\NRDC Exhibit 3.
11:40:13 AM	Objection by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Objection: Mr. Lindsey makes same objection and wants it noted that his objection is continuing for all of Mr. Fisk's exhibits that are just exerpts. Mr. Lindsey states that until the witness has the time to review the entire documents, then they reserve the right to change or modify his answers. State that they can submit in post hearing brief any modification to answers.
11:40:56 AM	Larry Cook (OAG)	
	Note: Kathy Gillum	Document is redacted. Mr. Fisk states it is public record.

11:41:37 AM	Quang Nguyen (PSC)	
	Note: Kathy Gillum	Question: Was the document filed with the Georgia PSC?. Mr. Fisk states yes.
11:41:54 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC\NRDC Exhibit 3.
11:42:39 AM	Objection by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Objection: Mr. Ingram states that the document speaks for itself.
11:42:58 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness requests clarification of the question.
11:43:18 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Intervenors Exhibit 3.
11:44:16 AM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk moves to admit as SC\NRDC Exhibit 3.
11:45:46 AM	Exhibits SC\NRDC 4,5,6 & 7	
	Note: Kathy Gillum	Mr. Fisk moves to admit SC\NRDC Exhibits 4, 5, 6 and 7. (Exhibit 4): Document titled, "Case No. 11-1439-EL-FOR, Duke Energy Ohio, Inc. 2011 Electric Long-Term Forecast Report and Resource Plan, Public Version"; (Exhibit 5): Document titled, "Integrated Resource Plan, TVA's Environmental & Energy Future, March, 2011; (Exhibit 6): Document titled, "2011 Integrated Resource Plan Volume 1, dated March 31, 2011"; (Exhibit 7): Document titled, "2. Planning Scenarios, 2011 Integrated Resource Plan". Documents marked as SC/NRDC Exhibits 4, 5, 6 and 7 respectively.
11:46:16 AM	Objection by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Mr. Ingram states that they have the same objection as before.
11:47:09 AM	Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook stated that Kentucky has a standard set of criteria for IRPs.
11:48:34 AM	Objection by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Objection: Mr. Ingram states that the document speaks for itself.
11:49:08 AM	Larry Cook (OAG)	
11:49:42 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness makes a statement regarding combined cycle plants.
11:53:32 AM	Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook asks if the question should be for an IRP case instead of this case.
11:53:58 AM	David Sinclair (LG&E-KU)	
11:54:14 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC\NRDC Exhibit 6, pages 159-161
11:55:48 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC\NRDC Exhibit 7.
11:56:06 AM	Objection by Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook states that the questions are not relative to case at hand. Lindsey Ingram continues his objections.
11:56:31 AM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman states admitted subject to objections.
11:56:47 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding load factors.
11:57:25 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Answer: Total amount of energy divided by actual energy assumed.
11:58:13 AM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Mr. Sullivan's testimony.

11:59:56 AM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness explains load factors.
12:01:14 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding different levels of electricity being used in a home.
12:02:15 PM	David Sinclair (LG&E-KU)	
12:02:26 PM	Examination by Shannon Fisk (SC\NRDC) continues	
12:02:41 PM	David Sinclair (LG&E-KU)	
12:11:12 PM	Exhibit SC\NRDC 8	
	Note: Kathy Gillum	Exhibit: Document titled, "Table 8.(3)(e)(3) LG&E-KU DSM Energy and Demand Impacts". Document introduced by Shannon Fisk and marked as SC\NRDC Exhibit 8.
12:11:38 PM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC\NRDC Exhibit 8. Witness is asked to make calculations based upon handout (Exhibit 8)
12:13:36 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness makes calculations based upon the handout (Exhibit 8).
12:17:20 PM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Appendix A to Rebuttal Testimony
12:18:16 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk moves to admit SC\NRDC Exhibit 8. No objections.
12:18:40 PM	Examinatin by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Mr. Fisk continues questions regarding Appendix A to Sinclair Rebuttal Testimony.
12:27:18 PM	Objection by Larry Cook (OAG)	
	Note: Kathy Gillum	Objection: Mr. Cook stated that he was not sure about the line of this questioning.
12:28:09 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman states that we would break for an hour for lunch.
12:28:44 PM	Vice Chair Gardner (PSC)	
12:28:53 PM	Larry Cook (OAG)	
12:29:12 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk moves to admit SC\NRDC Exhibit 9. (Exhibit 9): Document titled, "Appendix a to Sinclair Rebuttal Testimony, LG&E -KU DSM Program Review Report dated March 18, 2011". Document is marked as SC\NRDC Exhibit 9.
12:29:27 PM	Case Recessed	
1:33:05 PM	Case Started	
1:33:15 PM	Hearing Resumed	
	Note: Kathy Gillum	Hearing was resumed after a break for lunch. Witness (Sinclair) is still on stand.
1:33:28 PM	Examinatin by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC/NRDC Exhibit 9, pages 25 and 26, 3rd paragraph.
1:35:09 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman states that this witness is clearly not an authority on DSM.
1:35:53 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk states that Mr. Sinclair has questioned their witnesse's testimony regarding DSM.
1:39:11 PM	Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook states that the environmentals could address the issue in their brief.

1:39:38 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman asks if Mr. Fisk would be putting on witnesses. Chairman instructs Fisk to proceed.
1:40:32 PM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Page 24 of Exhibit 9.
1:41:22 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states that it is his belief that the companies are implementing all of the DSM programs approved by the Commission.
1:43:21 PM	Examinatin by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding page 25, Table 4. Questions regarding page 5 of Sinclair Rebuttal Testimony, lines 11 to 13.
1:45:07 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states they do not produce a forecast for no change.
1:48:25 PM	Exhibit SC/NRDC 10	
	Note: Kathy Gillum	Exhibit: Document titled, "Energy Efficiency Resource Standards:. Document introduced by Mr. Fisk and marked as SC\NDRC Exhibit 10.
1:48:43 PM	Examination by Shannon Fisk (SC\NDRC) continues	
	Note: Kathy Gillum	Questions regarding page 6 and 7 of SC/NRDC Exhibit 10.
1:49:33 PM	Objection by Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Objection: Mr. Ingram states that Mr. Fisk is asking witness to draw conclusions about a document that Mr. Sinclair has not reviewed and is outside of the knowledge of the witness.
1:50:28 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Explains that this document is a relative summary of what is offered in other states.
1:50:50 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman asks if Mr. Fisk would like to see if the witness is an expert in this area.
1:53:04 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk states that he is not offering the witness as an expert, but is challenging his expertise.
1:54:18 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states that he did not pass judgment on their witnesses claim.
1:55:54 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk moves to admit Exhibit 10.
1:56:08 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	So ordered.
1:57:05 PM	Exhibit SC/NRDC 11	
	Note: Kathy Gillum	Exhibit: Document titled, "State of the Efficiency Program Industry, Budgets, Expenditures, and Impacts 2011 dated March 14, 2012". Document introduced by Mr. Fisk, and marked as SC\NRDC Exhibit 11.
1:57:53 PM	Examination by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Exhibit 11.
1:58:43 PM	Exhibit SC\NRDC 12	
	Note: Kathy Gillum	Exhibit: Document titled, "About CEE Members, Consortium for Energy Efficiency" (shows a listing of members). Document introduced by Mr. Fisk and marked as SC\NRDC Exhibit 12.
1:58:52 PM	Examinatin by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding Exhibit 12, page 2.
2:02:15 PM	Shannon Fisk (SC\NRDC)	
	Note: Kathy Gillum	Mr. Fisk moves to admit Exhibits 11 and 12. No objections.

2:02:50 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	So ordered.
2:03:02 PM	Examinatin by Shannon Fisk (SC\NRDC) continues	
	Note: Kathy Gillum	Questions regarding wind.
2:04:26 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states there would be a shortfall using only wind.
2:09:42 PM	Private Mode On	
2:09:49 PM	Case Recessed	
2:17:50 PM	Case Resumed	
3:00:19 PM	Case Recessed	
3:00:24 PM	Case Started	
3:00:30 PM	Case Recessed	
3:13:11 PM	Case Started	
3:13:15 PM	Public Session	
	Note: Kathy Gillum	Confidential session has concluded. The remainder of the hearing is in public mode.
3:13:25 PM	Examination by Shannon Fisk (SC/NRDC) continues	
	Note: Kathy Gillum	Questions regarding DSM in the CPCN filing. Questions regarding whether additional DSM programs would be considered that have not been yet approved by the Commission.
3:15:15 PM	Examination by Shannon Fisk (SC/NRDC) continues	
	Note: Kathy Gillum	Questions regarding future consideration of DSM programs.
3:16:16 PM	David Sinclair (LG&E-KU)	
3:17:03 PM	Examination by Shannon Fisk (SC/NRDC) continues	
	Note: Kathy Gillum	Questions regarding SC/NRDC Exhibit 9, page 14 and 15.
3:18:54 PM	David Sinclair (LG&E-KU)	
3:20:19 PM	Examination by Quang Nguyen (PSC)	
	Note: Kathy Gillum	Questions regarding Page 18 of Direct Testimony, line 17 through 20.
3:21:30 PM	David Sinclair (LG&E-KU)	
3:22:33 PM	Examination by Quang Nguyen (PSC) continues	
	Note: Kathy Gillum	Questions regarding Page 19 of Direct Testimony regarding Purchase price of the Bluegrass CTs. Questions regarding page 20 of Direct Testimony, regarding deferred capacity. Questions regarding peak demand reduction.
3:26:34 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding reserve requirements; how computed, etc.
3:27:18 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness answers question by giving a Summary of how they came up with reserve requirements.
3:36:03 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding Page 4 of Direct Testimony
3:38:37 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness states that 40% of peak is made up of residential customers.
3:40:04 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Question: Has the 2013 Forecast has been done yet?
3:41:17 PM	David Sinclair (LG&E-KU)	
	Note: Kathy Gillum	Witness stated that the 2013 forecast has not yet been done.
3:42:53 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding the 1% target (listed in DSS-1).

3:44:12 PM	Examinatin by Kurt Boehm (KIUC)	
	Note: Kathy Gillum	Questions regarding page 98 of SC-2. Questions regarding the TVA IRP (SC-5), page 151. Questions regarding SC-7.
3:50:46 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding modeling including CO2 prices.
3:53:57 PM	Shannon Fisk (SC/NRDC)	
3:54:36 PM	Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	The reason was there was a settlement agreement.
3:54:57 PM	Witness Excused (Sinclair)	
3:55:14 PM	Witness, Lonnie Bellar (LG&E-KU)	
	Note: Kathy Gillum	Witness called to testify by Lindsey Ingram on behalf of LG&E-KU).
3:55:53 PM	Qualification of Witness by Duncan Crosby	
	Note: Kathy Gillum	Witness makes correction to page 3, line 16 thru 18. Witness adopts pre-filed testimony and DR responses with the above corrections.
3:57:11 PM	Examination by Kurt Boehm (KIUC)	
	Note: Kathy Gillum	Questions regarding the rate impact.
3:58:15 PM	Lonnie Bellar (LG&E-KU)	
	Note: Kathy Gillum	The rate impact is for the percentages in this case. Inclusive of all of the retirements, etc.
4:01:38 PM	Examination by Quang Nguyen (PSC)	
	Note: Kathy Gillum	Questions regarding DSM programs. Question regarding whether the companies have ever offered industrial DSM programs. Questions regarding the DSM Advisory Group. Questions regarding PSC 2nd DR, Item 1.
4:06:06 PM	Lonnie Bellar (LG&E-KU)	
	Note: Kathy Gillum	Witness states that the current plans are to retain those pieces of property. (Green River and Tyrone).
4:08:00 PM	Data Request (PSC)	
	Note: Kathy Gillum	Mr. Nguyen asks the witness to provide a listing identifying any generating units owned by either LG&E or KU that are no longer in use, in which the cost of removal or salvage was included in the depreciation rate. Mr. Nguyen asked for the identity of the units, the plans for the properties and the costs of removal and\or salvage.
4:08:19 PM	Examination by Quang Nguyen (PSC) continues	
	Note: Kathy Gillum	Questions regarding the timeline for abandoned structures.
4:09:16 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding wind case a few years back that the Commissoin rendered a split decision on. Questions regarding Table 7.2H2 in the IRP.
4:14:21 PM	Lonnie Bellar (LG&E-KU)	
4:15:06 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding industrial DSM programs. Questions regarding load switch devices.
4:21:01 PM	Lonnie Bellar (LG&E-KU)	
4:21:20 PM	Re-Direct by Duncan Crosby	
	Note: Kathy Gillum	REQ Sales. Public Authority Sales are to gov.
4:22:01 PM	Examination by Shannon Fisk (SC/NRDC)	
	Note: Kathy Gillum	Questions regarding if any analysis has been done for Industrial DSMs.
4:22:45 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	No market characterization study has been done.

4:23:52 PM	Lindsey Ingram (LG&E-KU)	
	Note: Kathy Gillum	Mr. Ingram states that that completes their case.
4:24:57 PM	Case Recessed	
4:29:32 PM	Case Started	
4:29:37 PM	Lindsey Ingram (LG&E-KU)	
4:29:50 PM	Quang Nguyen (PSC)	
4:30:41 PM	Witness Excused (Bellar)	
4:30:55 PM	Witness, Dylan Sullivan (NRDC)	
	Note: Kathy Gillum	Witness called to testify by Shannon Fisk.
4:31:28 PM	Qualification of Witness by Shannon Fisk (SC/NRDC)	
	Note: Kathy Gillum	Witness corrects DES-2 (changes the headings). Witness adopts pre-filed testimony and DR Responses, with the above changes.
4:33:01 PM	Examination by Quang Nguyen (PSC)	
	Note: Kathy Gillum	Questions regarding Page 7 of Direct Testimony.
4:34:44 PM	Dylan Sullivan (NRDC)	
	Note: Kathy Gillum	Witness states that the company's own analysis suggests they could do more energy efficiency. Witness states he chose a conservative factor.
4:37:21 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Vice Chair Gardner asked : Is there value in a company being more diverse.
4:38:27 PM	Witness Excused (Sullivan)	
4:38:35 PM		
4:38:57 PM	Witness Paul Chernick (SC/NRDC)	
	Note: Kathy Gillum	Called to testify Shannon Fisk.
4:39:39 PM	Qualification of witness by Kristin Henry (SC/NRDC)	
	Note: Kathy Gillum	Witness adopts pre-filed testimony and DR Responses.
4:40:09 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Mr. Gardner asked if there was value in having a more diverse company.
4:40:33 PM	Paul Chernick (SC/NRDC)	
	Note: Kathy Gillum	Witness states that yes there were.
4:41:25 PM	Vice Chair Gardner (PSC)	
	Note: Kathy Gillum	Questions regarding previous testimony of John Voyles.
4:42:01 PM	Paul Chernick (SC/NRDC)	
4:42:41 PM	Witness Excused (Chernick)	
4:42:58 PM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Lindsey Ingram requests a decision by April 30th due to contract with Bluegrass. Lindsey Ingram states that they can submit a brief quickly. Kurt Boehm agrees. Joe Childers requests a reply brief. Lindsey Ingram would not agree to a responsive brief. Lindsey Ingram asks for principal briefs only. Quang Nguyen agreed that simultaneous briefs would be more beneficial for staff. Quang Nguyen agrees that the deadline should be taken into reconsideration. Quang Nguyen suggested 2 weeks from this date, which would be April 3rd.
4:46:17 PM	Quang Nguyen (PSC)	
	Note: Kathy Gillum	Mr. Nguyen states that Post Hearing Data Requests are due in 10 days. Completed IRPs.
4:46:52 PM	Case Recessed	
4:46:48 PM	Hearing Adjourned	
	Note: Kathy Gillum	The hearing was adjourned by Chairman Armstrong.

Exhibit List Report

Case Number: 2011-00375_20Mar12

Case Title: Louisville Gas & Electric Company and Kentucky Utilities Company
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Name	Description
LG&E-KU Exhibit 1	3 documents with yellow highlighted information to be used as corrections to pre-filed testimony and responses to data requests previously filed.
SC/NRDC Confidential Exhibit 13	
SC/NRDC Confidential Exhibit 14	
SC/NRDC Confidential Exhibit 15	
SC/NRDC Confidential Exhibit 16	
SC/NRDC Confidential Exhibit 17	
SC/NRDC Confidential Exhibit 18	
SC/NRDC Exhibit 1	Letter dated December 17, 2010 from LG&E-KU regarding Request for Proposals to Sell Capacity and Energy (RFP)
SC/NRDC Exhibit 10	Document titled, "Energy Efficiency Resource Standards:
SC/NRDC Exhibit 11	Document titled, "State of the Efficiency Program Industry, Budgets, Expenditures, and Impacts 2011 dated March 14, 2012"
SC/NRDC Exhibit 12	Document titled, "About CEE Members, Consortium for Energy Efficiency" (shows a listing of members)
SC/NRDC Exhibit 19	Document titled, "Response to Commission Staff's First Information Request dated October 26, 2011, Case No. 2011-00375, Question No. 19, David Sinclair"
SC/NRDC Exhibit 2	Document titled, "State of South Carolina, Docket Number 2011-10-E, Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (IRP)
SC/NRDC Exhibit 3	Document titled, Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 ..., Docket No. 34218 dated August 4, 2011"
SC/NRDC Exhibit 4	Document titled, "Case No. 11-1439-EL-FOR, Duke Energy Ohio, Inc. 2011 Electric Long -Term Forecast Report and Resource Plan, Public Version"
SC/NRDC Exhibit 5	Document titled, "Integrated Resource Plan, TVA's Environmental & Energy Future, March, 2011"
SC/NRDC Exhibit 6	Document titled, "2011 Integrated Resource Plan Volume 1, dated March 31, 2011"
SC/NRDC Exhibit 7	Document titled, "2. Planning Scenarios, 2011 Integrated Resource Plan"
SC/NRDC Exhibit 8	Document titled, "Table 8.(3)(e)(3) LG&E-KU DSM Energy and Demand Impacts"
SC/NRDC Exhibit 9	Document titled, "Appendix A to Sinclair Rebuttal Testimony, LG&E-KU DSM Program Review Report dated March 18, 2011".

Q. How does the Joint Load Forecast compare to growth experienced by the Companies historically?

A. On a combined company basis, the number of native electric customers increased from 925,251 in 2006 to 940,331 in 2010, a compound annual growth rate of 0.4 percent. Actual sales (after the impact of DSM and interruptible load programs) for KU and LG&E rose from 32,640 gigawatt-hours ("GWh") in 2006 to 34,276 GWh in 2010, increasing at a compound annual growth rate of 1.2 percent. On a weather-normalized basis, average sales growth was flat during this period, which included the recession beginning in 2008. Combined energy requirements grew from 34,606 GWh in 2006 to 36,373 GWh in 2010. Peak demand fluctuated over the 2006-2010 period. On an actual basis, peak demand increased from 6,863 MW in 2006 to 7,175 MW in 2010. The reduced demands in 2008 and 2009 were primarily the result of mild summer weather; the peak demands for these years occurred in the winter months. The peak demands for 2006, 2007, and 2010 occurred in the summer months. On a weather-normalized basis, the system peak increased by a compound growth rate of 0.4 percent from 2006 to 2010.

Q. Please describe how LG&E and KU prepared their energy sales forecasts.

A. The energy forecast was developed separately for LG&E and KU. Forecast models are primarily econometric in nature and, as such, satisfy two critical forecasting requirements. First, each forecast incorporates specific local, or service territory, economic and demographic data. Second, this approach allows for the quantification of the relationships between electric sales and the variables to which they are related. Such factors as weather, employment, and prices provide for well-specified models that produce robust results.

LG&E\KU EXHIBIT 1

Q. How does the Joint Load Forecast compare to growth experienced by the Companies historically?

A. On a combined company basis, the number of native electric customers increased from 925,251 in 2006 to 940,331 in 2010, a compound annual growth rate of 0.4 percent. Actual sales (after the impact of DSM and interruptible load programs) for KU and LG&E rose from 32,640 gigawatt-hours ("GWh") in 2006 to 34,276 GWh in 2010, increasing at a compound annual growth rate of 1.2 percent. On a weather-normalized basis, average sales growth was flat during this period, which included the recession beginning in 2008. Combined energy requirements grew from 34,606 GWh in 2006 to 36,373 GWh in 2010. Peak demand fluctuated over the 2006-2010 period. On an actual basis, peak demand increased from 6,863 MW in 2006 to 7,175 MW in 2010. The reduced demands in 2008 and 2009 were primarily the result of mild summer weather; the peak demands for these years occurred in the winter months. The peak demands for 2006, 2007, and 2010 occurred in the summer months. On a weather-normalized basis, the system peak increased by a compound growth rate of 0.4 percent from 2006 to 2010.

Deleted: 33,550
Deleted: 35,238
Formatted: Highlight
Formatted: Highlight
Deleted: 35,070
Formatted: Highlight
Deleted: 35,382
Formatted: Highlight

Q. Please describe how LG&E and KU prepared their energy sales forecasts.

A. The energy forecast was developed separately for LG&E and KU. Forecast models are primarily econometric in nature and, as such, satisfy two critical forecasting requirements. First, each forecast incorporates specific local, or service territory, economic and demographic data. Second, this approach allows for the quantification of the relationships between electric sales and the variables to which they are related. Such factors as weather, employment, and prices provide for well-specified models that produce robust results.

KU RESIDENTIAL

	Customers		Personal Income ($)		Total HDD		Total CDD		Price Elasticity of Demand	
	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast
2011	428,733	NA	77,720	NA	4,515	NA	1,212	NA	-0.15	-0.10
2012	433,020	426,699	80,109	80,109	4,515	4,544	1,212	1,235	-0.15	-0.10
2013	437,351	429,052	82,005	82,005	4,515	4,544	1,212	1,235	-0.15	-0.10
2014	441,724	432,065	84,968	84,968	4,515	4,544	1,212	1,235	-0.15	-0.10
2015	446,141	435,969	87,621	87,621	4,515	4,544	1,212	1,235	-0.15	-0.10
2016	450,603	439,909	90,572	90,572	4,515	4,544	1,212	1,235	-0.15	-0.10
2017	455,109	444,329	93,185	93,185	4,515	4,544	1,212	1,235	-0.15	-0.10
2018	459,660	448,792	96,262	96,262	4,515	4,544	1,212	1,235	-0.15	-0.10
2019	464,257	452,396	99,157	99,157	4,515	4,544	1,212	1,235	-0.15	-0.10
2020	468,899	456,028	102,389	102,389	4,515	4,544	1,212	1,235	-0.15	-0.10
2021	473,588	459,690	105,506	105,506	4,515	4,544	1,212	1,235	-0.15	-0.10
2022	478,324	463,381	108,340	108,340	4,515	4,544	1,212	1,235	-0.15	-0.10
2023	483,107	467,102	111,023	111,023	4,515	4,544	1,212	1,235	-0.15	-0.10
2024	487,938	470,852	113,700	113,700	4,515	4,544	1,212	1,235	-0.15	-0.10
2025	492,818	474,633	116,549	116,549	4,515	4,544	1,212	1,235	-0.15	-0.10

LG&E RESIDENTIAL

	Customers		Personal Income ($)		Total HDD		Total CDD		Price Elasticity of Demand	
	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast
2011	350,540	NA	40,883	NA	4,108	NA	1,540	NA	-0.15	-0.10
2012	353,639	356,680	41,945	41,945	4,108	4,141	1,540	1,560	-0.15	-0.10
2013	356,827	358,647	42,994	42,994	4,108	4,141	1,540	1,560	-0.15	-0.10
2014	359,848	361,166	44,709	44,709	4,108	4,141	1,540	1,560	-0.15	-0.10
2015	363,093	364,429	46,326	46,326	4,108	4,141	1,540	1,560	-0.15	-0.10
2016	366,004	367,723	48,122	48,122	4,108	4,141	1,540	1,560	-0.15	-0.10
2017	369,245	371,417	49,763	49,763	4,108	4,141	1,540	1,560	-0.15	-0.10
2018	372,416	375,148	50,999	50,999	4,108	4,141	1,540	1,560	-0.15	-0.10
2019	375,716	378,160	52,714	52,714	4,108	4,141	1,540	1,560	-0.15	-0.10
2020	379,229	381,197	54,490	54,490	4,108	4,141	1,540	1,560	-0.15	-0.10
2021	382,818	384,258	55,993	55,993	4,108	4,141	1,540	1,560	-0.15	-0.10
2022	386,509	387,343	57,697	57,697	4,108	4,141	1,540	1,560	-0.15	-0.10
2023	390,036	390,453	59,539	59,539	4,108	4,141	1,540	1,560	-0.15	-0.10
2024	393,756	393,588	61,375	61,375	4,108	4,141	1,540	1,560	-0.15	-0.10
2025	397,401	396,749	63,127	63,127	4,108	4,141	1,540	1,560	-0.15	-0.10

SC\NRDC EXHIBIT 1

LG&E KU
PPL companies

LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
www.lge-ku.com

Charles A. Freibert, Jr.
Director Marketing
T 502-6273673
charlie.freibert@lge-ku.com

Company
Attn: Director Marketing and Trading
Adress

December 17, 2010

Subject: Request for Proposals to Sell Capacity and Energy (RFP)

Dear Colleague in Development, Marketing and Trading of Electrical Power,

In order to meet pending environmental regulations and future load growth, Louisville Gas and Electric Company and Kentucky Utilities Company (the "Companies") are evaluating alternatives means to provide least-cost firm generating capacity and energy to our customers. To this end, the Companies are requesting proposals from parties wishing to sell capacity and energy that will qualify as a Designated Network Resource (DNR) either as an owned asset by the Companies or a Power Purchase Agreement with the Companies. The Companies will consider offers that are reliable, feasible and represent the least-cost, including cost for transmission service and upgrades and voltage support, means of meeting our customers' energy needs. The Seller should make its proposal as comprehensive as possible so that the Companies may make a definitive and final evaluation of the proposal's benefits to its customers without further contact with the Seller. However, the Companies reserve the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Companies' internal evaluation of cost, risk, and value.

This inquiry is not a commitment to purchase and shall not bind the Companies or any subsidiaries of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine with which Respondent(s), if any, it wishes to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses Respondents incur in connection with preparation of a response to this RFP. The Companies will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Companies at their sole discretion.

1. **Background** - This RFP is being issued in order to evaluate alternatives for meeting existing and pending EPA regulations and to meet future load growth. All

alternatives (including any of the Companies' self-build options) will be evaluated in the context of meeting customers' load in a least-cost manner. If the Companies determine that a proposal is in the best interest of the Companies' customers, the Companies will enter into negotiations which may lead to the execution of definitive agreements. The Companies will consider all applicable factors including, but not limited to, the following to determine the lowest total reasonable cost: (i) the terms of the purchased power proposal or facility or asset sale; (ii) Seller's creditworthiness; (iii) if applicable, the development status of Seller's generation facility including, but not limited to, site chosen, permitting, and transmission; or the operating history of Seller's generation facility; (iv) the degree of risk as to the availability of the power in the timeframe required; (v) the anticipated reliability of the power, particularly at times of winter and summer peak; and (vi) all other factors such as the cost of interconnection or transmission that may affect the Companies or their customers. The Companies are committed to implementing the best overall long-term solution for their customers.

2. **Requirements** - The Companies are interested in Power Purchase Agreements ("PPA"), Tolling Agreements ("TA") or Build Own Transfer Agreements ("BOT"), or alternative power supplies (combined "Supply Agreements") for minimum quantities of 1 MW up to a total of 700 MW of firm summer and winter capacity and associated energy per facility or offer with preference given to offers of 50 MWs or greater. The power being proposed must be generated from a defined source, a specific unit(s) or system that will qualify as a DNR and supply capacity/energy during the peak demand of the Companies' customers (typical Midwest seasonal load characteristics). The delivery of capacity and energy should begin no earlier than January 1, 2014, but later start dates will be considered. While the Companies prefer longer term proposals, shorter terms will be considered. The Companies may procure more or less than 700 MW and may aggregate capacity and energy from multiple Sellers to meet its needs. A Seller offering power from a resource connected directly to the Companies' transmission system must conform to the Companies' Open Access Transmission Tariff (OATT) and must obtain in a timely manner an Interconnection Agreement for the facility.

3. **Key Terms and Conditions** - For a Supply Agreement, the Seller's proposal should include the proposed terms and conditions, which should include, where applicable to the Seller's proposal, among other things:

   3.1. Seller will guarantee all pricing and terms that affect pricing such as but not limited to heat rate, fuel cost, operation and maintenance cost, etc., for at least 120 days after the Proposal Due Date.

   3.2. Any Capacity Payments to the Seller will be based upon guaranteed capacity at the Summer Design Conditions. Unless the location of the Seller's facility justifies alternate conditions. Summer Design Conditions shall be the following.

      3.2.1. Dry Bulb: 89°F

3.2.2. Mean Coincident Wet Bulb: 79.33°F
3.2.3. Relative humidity: 66%

3.3. Seller will guarantee the annual and seasonal availability and describe required maintenance outage schedule.

3.4. Seller should address in their proposal its remedies for failure to meet availability guarantees.

3.5. Seller will be responsible for any and all compliance related cost and fines (environmental, NERC, FERC, etc) incurred due to the non-compliance of the assets designated to supply power to the Companies.

3.6. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

3.7. The Companies termination rights will include, but may not be limited to: (i) failure to post or maintain required financial credit requirements, (ii) failure to meet key development and implementation milestones, (iii) failure to meet reliability requirements, and (iv) failure to cure a material breach under the Supply Agreement.

4. **Dispatching and Scheduling** (Required Proposal Content) - The Companies prefer flexibility in the utilization of the generation resource being offered by the Seller. The Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time control/dispatch of generation to follow load changes and respond to system frequency changes. The Seller should state its desire and willingness to allow and cooperate with the Companies in establishing real-time control of generation.

5. **Ancillary Services** (Required Proposal Content) - Under a Supply Agreement, the Companies desire to have the unrestricted right to utilize all ancillary services associated with generation being offered by the Seller. The Seller should describe the ancillary service capability of its proposal e.g., black start capability, voltage support, load following, energy imbalance, spinning reserve, and supplemental reserve. The ancillary services that would be available to the Companies should not be limited to those defined in this paragraph. The Companies desire to have the unrestricted rights to any future ancillary services defined by the industry and capable of being provided by the generation capacity being offered. In the case where the Companies purchase only part of the generation capacity from a unit, system or facility, then the Companies desire to have unrestricted rights to ancillary services on a prorated basis.

6. **Pricing** (Required Proposal Content) - The Seller's pricing must be a delivered price to the Companies' transmission system. The Companies will only be responsible for Network Integrated Transmission Service (NITS) on the Companies transmission system. Prices must be firm, representing best and final data and quoted in U.S. dollars. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

   6.1. The Seller's proposal must provide the product and generation characteristics on the attached form. Pricing information can be provided on the form or separately in another format that is appropriate for the offer. The Seller is encouraged to provide as much information as possible to aid in the evaluation of the offer. These attached data forms may be utilized in any filings with regulatory agencies (such as the KPSC) related to this RFP.

7. **Delivery** (Required Proposal Content) - The Companies consider reliable power delivery at the time of the typical summer and winter peak demand of its customers to be of the utmost importance. The delivery point is the Companies' transmission system. Under a Supply Agreement, Sellers would be responsible for providing firm transmission to the Companies' transmission system. The Seller is responsible for all costs associated with transmission interconnections and shall provide all studies and Interconnection Agreements. The Seller is responsible for all transmission including system upgrades up to the delivery point and shall provide all studies and Transmission Reservations/Agreements. All costs associated with interconnections

and transmission up to the delivery point should be included in the Seller's pricing where appropriate under current FERC orders and rulings. Southwest Power Pool (SPP) is an Independent Transmission Operator that administers the Companies' OATT. Tennessee Valley Authority (TVA) serves as the Companies' Reliability Coordinator (RC). For purposes of the Companies' evaluation of the proposals, the Companies may estimate any transmission costs that are not supported by the appropriate studies including deliverability and the associated voltage support to the Designated Network Load ("DNL") of the Companies. If the Seller has not completed all required transmission studies, it is essential that the following information be provided in order for the Companies to evaluate the proposal:

- Size of the unit
- Point of interconnection to the grid
- Impedance of the generator step-up transformer
- Transient and sub transient characteristics of the generator

8. **Environmental** - For the sale of generation capacity and energy to the Companies under a Supply Agreement, the Seller would be responsible for obtaining all necessary permits and providing all credits and allowances needed to comply with the permit requirements for the life of the agreement, where permits, credits and allowances are applicable for the product being sold. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by Seller. The Companies require that Sellers provide the following information for evaluation:
   - Unit heat rate, fuel specification, and control technologies employed.
   - Emissions rates for NOx, SOx, CO, CO2, PM_{10}, and Hg.
   - Copy of air permit or permit application if available.
   - Timing and status of all permit applications including water withdrawal, wastewater disposal, fuel byproducts handling and disposal, etc.

9. **Development Status** – Seller shall provide a comprehensive narrative of the status of the development of any generation project intended to be used to meet Seller's obligations to the Companies. Seller's narrative shall include the following.
   9.1. A comprehensive development and construction schedule,
   9.2. A listing of all required permits and governmental approvals and their status,
   9.3. A listing of all required electric interconnection and or transmission agreements and their status,
   9.4. A financing plan, and
   9.5. A summary of key contracts (fuel, construction, major equipment) to the extent that they exist.

10. **Other Information Requirements** - Sellers shall provide a complete description of the generation facilities that would be used to fulfill the Seller's obligations to the Companies. The description should include the following:
    - Seller's operating experience with similar technology.
    - Guaranteed capacity rating at Summer Design Conditions
    - Guaranteed annual and seasonal availabilities including EFOR values and planned maintenance schedules.
    - Technology employed (combined cycle, pulverized coal, CFB, super-critical, etc.)
    - Plant location along with proof or status of ownership or control of site.
    - Zoning status of plant site.
    - If the plant site is subject to site approval by a governmental authority, provide a description of the approval status including a copy of the application. If approval has been granted, provide a copy of the approval.
    - Status of engineering and design work.
    - Key project participants including owners, operators, engineer/contractors, fuel suppliers

    The Seller should also provide any additional information the Seller deems necessary or useful to the Companies in making a definitive and final evaluation of the benefits of the Seller's proposal without further interaction between the Companies and Seller.

11. **Financial Capability** - Should the Companies elect to enter into an agreement with a Seller who fails to meet its obligations at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, the Sellers will be required to demonstrate, in a manner acceptable to the Companies, the Seller's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of the Supply Agreement. Under no circumstances, should the Companies' customers be exposed to increased costs relative to the cost defined in an agreement between the Seller and the Companies.

    11.1. At all times, the Seller will be required to maintain an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

    11.2. Upon execution of the Supply Agreement, Sellers will be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the Seller. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. This amount shall take into account the cost of replacement energy and associated environmental cost with the production of replacement energy and any byproducts of such replacement energy. If the Companies draw down the LOC amount at any time, the Seller must replace the LOC to the original value within five days.

12. **<u>Alternate Power Supplies</u>** - Alternate power supply arrangements may include the acquisition of generation assets, existing generation facilities, projects under development, system firm products, or other power supply arrangements that meet the Companies' requirements described in this RFP. The Seller must make all transmission arrangements for the delivery of alternate power supply arrangements to the delivery point and include the cost for transmission in the pricing. Sellers interested in proposing alternative power supplies must provide all information specified in this document and applicable to the alternate power supply needed for the Companies to fully evaluate the proposal. Those Sellers proposing the sale of generation facilities should include the following:
    - Complete description of the facilities included in the sale.
    - Firm offer price
    - Term sheet which identifies key terms and conditions
    - Latest condition report
    - Projected operating data including output, heat rate, and forced outage rate as appropriate
    - Projected operating expenses and capital expenditures
    - For existing facilities, provide historical operating data, operating expenses, and capital expenditures for a minimum of the latest five years or since the start of commercial operation if in commercial operation for less than five years.

13. **<u>RFP Schedule</u>** - All proposals must be complete in all material respects and be received no later than 4 p.m. EST on Friday, January 28, 2011. Email proposals must be followed up with a signed original within two business days.

RFP Issued	Wednesday, December 1, 2010
Proposals Due	Friday, January 28, 2011
Evaluation Completed	Friday, March 18, 2011

Proposals will not be viewed until 4 p.m. EST on Friday, January 28, 2011. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

14. <u>Treatment of Proposals</u>

14.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. The Companies also reserve the right to modify the RFP or request further information, as necessary, to complete its evaluation of the proposals received.

14.2. Sellers who submit proposals do so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of capacity and/or energy for any reason. Sellers are responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

15. **Confidentiality** - As regulated utilities, it is expected that the Companies will be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as "Confidential." Please note that confidential treatment is more likely to be granted if limited amounts of information are designated as confidential rather than large portions of the proposal. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to this information. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the Seller's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

16. **Contacts** - All correspondence should be directed to:

Charles A. Freibert, Jr.
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202

E-mail: charlie.freibert@lge-ku.com
Phone: 502-627-3673

In closing, I look forward to your response by 4 p.m. EST on Friday, January 28, 2011, and the possibility of doing business to meet the Companies' future power needs. Your interest in this request is greatly appreciated. Please contact me if you have any questions and would like to discuss further. For immediate concerns in my absence, please contact Donna LaFollette at 502-627-4765.

Sincerely,

Charles A. Freibert, Jr.

Charles A. Freibert, Jr.

EXHIBIT

STATE OF SOUTH CAROLINA	**BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**
(Caption of Case) **IN RE:** **Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (IRP)**	**COVER SHEET** **DOCKET NUMBER: 2011 - 10 - E**

(Please type or print)

Submitted by:	**Charles A. Castle**	**SC Bar Number:**	**79895**
Address:	**Duke Energy**	**Telephone:**	**704.382.4499**
	550 S Tryon St., DEC45A	**Fax:**	
	Charlotte, NC 28202	**Other:**	
		Email:	**alex.castle@duke-energy.com**

NOTE: The cover sheet and information contained herein neither replaces nor supplements the filing and service of pleadings or other papers as required by law. This form is required for use by the Public Service Commission of South Carolina for the purpose of docketing and must be filled out completely.

DOCKETING INFORMATION (Check all that apply)

☐ **Emergency Relief demanded in petition** ☐ **Request for item to be placed on Commission's Agenda expeditiously**

☒ **Other: Duke Energy Carolinas' 2011 Integrated Resource Plan and Motion for Confidential Treatment**

INDUSTRY (Check one)	NATURE OF ACTION (Check all that apply)		
☒ Electric	☐ Affidavit	☐ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certification
☐ Electric/Telecommunications	☐ Answer	☒ Motion	☐ Request for Investigation
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☒ Other: 2011 Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Re'	

SC\NRDC EXHIBIT 2

Duke Energy
Carolinas

Charles A Castle
Senior Counsel

Duke Energy Carolinas, LLC
550 South Tryon Street
Charlotte, NC 28202

Tel 704 382 4499
Fax 980.373 8534
alex castle@duke-energy com

September 1, 2011

VIA ELECTRONIC FILING AND
HAND DELIVERED CONFIDENTIAL VERSION

Ms. Jocelyn Boyd
Chief Clerk of the Commission
Public Service Commission of South Carolina
Synergy Business Park, Saluda Building
101 Executive Center Drive
Columbia, SC 29210

Re: Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan
Motion for Confidential Treatment
Docket No. 2011-10-E

Dear Ms. Boyd:

Enclosed for filing please find the CONFIDENTIAL VERSION of Duke Energy Carolinas, LLC's ("Duke Energy Carolinas" or "the Company") 2011 Integrated Resource Plan ("2011 IRP"). The Company respectfully requests that it be permitted to file the CONFIDENTIAL VERSION under seal and maintained as confidential pursuant to Order No. 2005-226, "ORDER REQUIRING DESIGNATION OF CONFIDENTIAL MATERIALS."

The 2010 IRP contains certain confidential information (portions of the tables in Appendix C (pages 139-141) and the tables in Appendix I (page 165)). The information contained therein is proprietary and commercially sensitive, and, if disclosed, could adversely affect the Company's ability to provide least cost resources for its customers. In addition, Appendix F of the 2011 IRP contains Duke Energy Carolinas' most recently-filed FERC Form 715. As FERC Form 715 contains critical energy infrastructure information that should be kept confidential and non-public, Duke Energy Carolinas is also filing it under seal and requests that the Commission treat this information as confidential and protect it from public disclosure.

Thus, Duke Energy Carolinas respectfully requests that the Commission grant its request for confidential treatment pursuant to 26 S.C. Code Ann. Regs. 103-804(S)(2)(Supp. 2010). A copy of the Public version of the 2011 IRP is being filed electronically and a copy of the CONFIDENTIAL VERSION of the 2011 IRP is being hand delivered to the Commission and the Office of Regulatory Staff under seal.

Please consider this correspondence as Duke Energy Carolinas' Motion for Confidential Treatment of the above-referenced information in Appendices C, F and I of the 2011 IRP.

Thank you for your consideration of this matter and please contact me with any questions.

Very truly yours,

Charles A. Castle

Enclosures
cc: Shannon Bowyer Hudson, Esq.

Duke Energy®

The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2011

TABLE OF CONTENTS

Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness.

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both demand response and conservation programs in the analysis.

The Company modeled the costs and impacts from EE and DSM programs based on the data included in Duke Energy Carolinas' approved Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831. For the analysis, Duke Energy Carolinas assumed these costs and impacts would continue through the duration of the planning period.

The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Energy Efficiency Plan for 2009 through 2012. The Company assumes for purposes of the IRP that total efficiency savings will continue to grow on an annual basis through 2031, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan.

Develop Theoretical Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This analysis began with a set of basic inputs which were varied to test the system under different future conditions, such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of resources required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The set of basic inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- System operational needs for load ramping, spinning reserve (10 to 15-minute start-up)

- The projected load and generation resource need; and
- A menu of new resource options with corresponding costs and timing parameters.

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, the Company developed a variety of portfolios to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen in order to focus on the optimal timing of CT, CC, and nuclear additions in the 2016 – 2031 timeframe.

The information as shown on the following pages outlines the planning options that the Company considered in the portfolio analysis phase. Each portfolio contains demand response and conservation identified in the base EE and DSM case and renewable portfolio standard requirements modeled after the NC REPS in NC and applied to SC. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck CC in 2012 and Dan River CC in 2013 and the unit retirements shown in Table 5 D.

The RPS assumptions are based on NC REPS in North Carolina. The assumptions for planning purposes are as follows:

Overall Requirements/Timing
- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

Additional Requirements
- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with out-of-state, unbundled RECs
- Solar requirement
    - 0.02% by 2010
    - 0.07% by 2012

- 0.14% by 2015
- 0.20% by 2018

- Hog waste requirement (NC only – using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
  - 0.07% by 2012
  - 0.14% by 2015
  - 0.20% by 2018
- Poultry waste requirement (NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
  - 71,400 MWh by 2012
  - 294,000 MWh by 2013
  - 378,000 MWh by 2014

The overall requirements were applied to all retail load and to wholesale customers who have contracted with Duke Energy Carolinas to meet their REPS requirement. The requirement that a certain percentage must come from Hog and Poultry waste was not applied to the South Carolina portion.

Conduct Portfolio Analysis

Duke Energy Carolinas tested the portfolio options under the nominal set of inputs, as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

For this IRP analysis, the Company selected six main scenarios to illustrate the impacts of key risks and decisions. Three of these scenarios fall into the Reference CO_2 Case and three fall into the Clean Energy Legislation Case.

- Reference Case: Cap and trade program with CO_2 prices based on Duke Energy's 2011 fundamental prices.
- Clean Energy Legislation: In addition to evaluating potential CO_2 cap and trade options, the impact of proposed Clean Energy legislation without a price on CO_2 emissions was also evaluated. Assumptions used in this analysis include:
  - 10% of retail sales by 2015 must be clean energy, increasing to 30% by 2030.
  - Alternative Compliance Payment (ACP) of 50$/MWhr.
  - "Clean Energy" includes renewable resources, EE, nuclear, natural gas CC, or alternative compliance payment.
  - Portfolios based on this legislation include the increased EE to meet 25

percent of the total clean energy target.

The six analyzed portfolios are shown below:

Reference CO_2 Case Scenarios:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. Lee Nuclear – Two Lee Nuclear unit portfolio with units on-line in 2021 and 2023 (2N 2021-2023)
3. Regional Nuclear – Co-ownership of nuclear units in the region. The portfolio consists of 215 MW of nuclear in 2018, 730 MW in 2021 and 2023, and 559 MW in 2028 (Reg Nuclear)

Clean Energy Legislation Scenarios:

4. Clean Energy CC – CC portfolio with the Clean Energy Legislation assumptions
5. Clean Energy 2N – Two Lee Nuclear unit portfolio with the Clean Energy Legislation assumptions
6. Clean Energy Regional Nuclear – Regional co-ownership of nuclear with the Clean Energy Legislation assumptions

An overview of the specifics of each portfolio is shown in Table A.1 below.

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward.

The Company evaluated the following sensitivities in the Reference CO_2 Case scenarios:

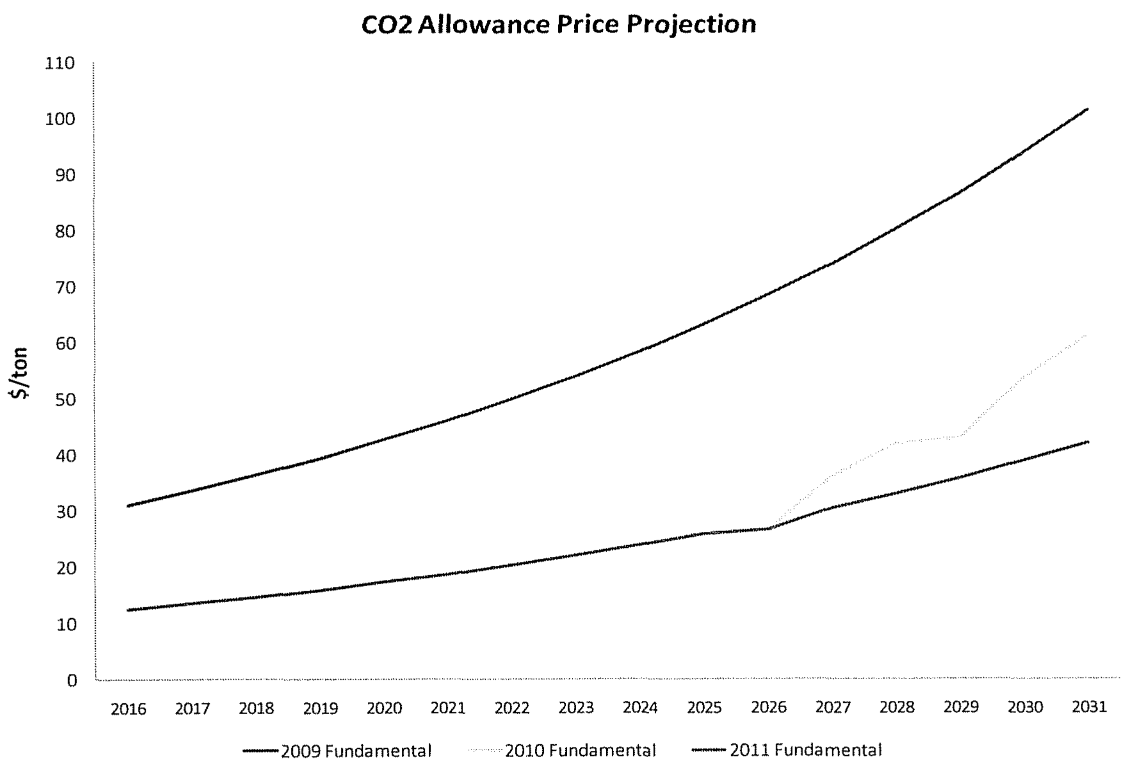
- Load forecast variations
  - Increase relative to base forecast (+15% for peak demand and +16% for energy by 2031)
  - Decrease relative to base forecast (-8% for peak demand and energy by 2031)
- Construction cost sensitivity[5]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 25% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 40% lower)

[5] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

- Nuclear Financing
  - Federal loan guarantees for the Lee nuclear station
- The Carbon reference case had CO_2 emission prices ranging from $12/ton starting in 2016 to $42/ton in 2031. The Company performed sensitivities based on the 2009 and 2010 fundamental CO_2 prices.
- High Energy Efficiency – This sensitivity includes the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented, this increased EE impacts resulted in approximately a 13% decrease in retail sales over the planning period.

Chart A.1 shows the CO_2 prices utilized in the analysis.

Chart A.1

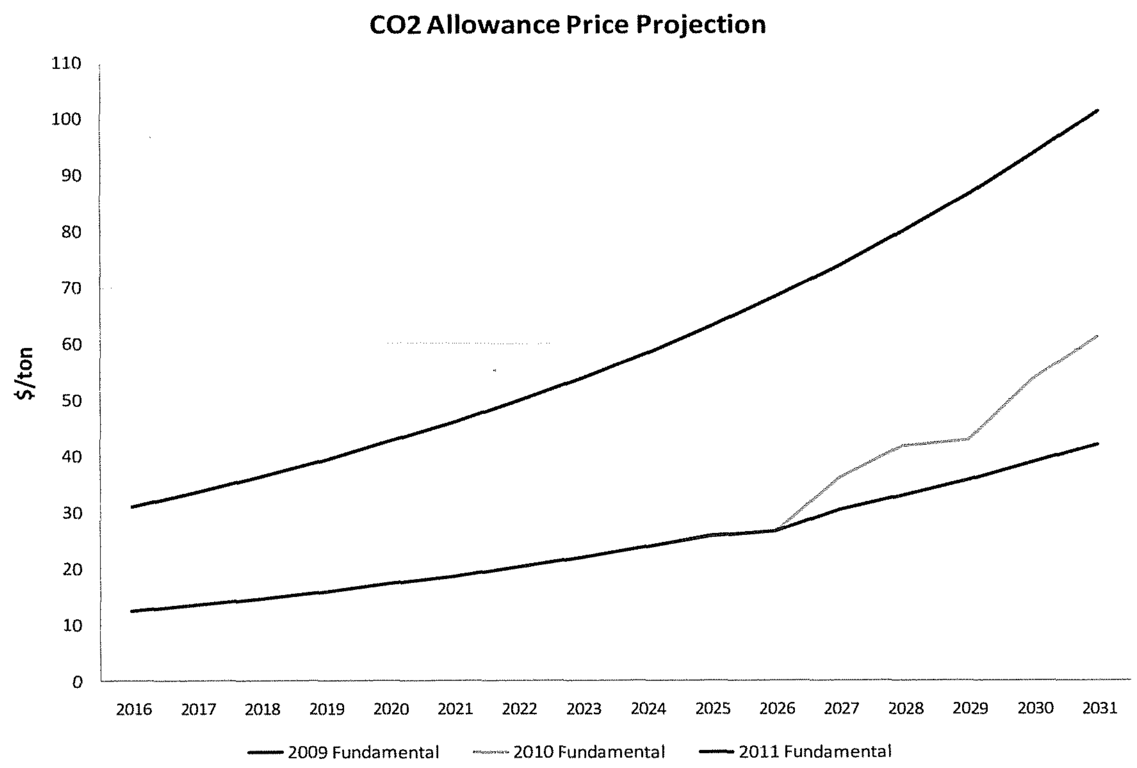


For the Clean Energy Legislation, the Company also performed a sensitivity by lowering the ACP to $30/MWhr and increasing the renewable energy assumptions to lower the Company's need to purchase ACPs.

- Nuclear Financing
  - Federal loan guarantees for the Lee nuclear station
- The Carbon reference case had CO_2 emission prices ranging from $12/ton starting in 2016 to $42/ton in 2031. The Company performed sensitivities based on the 2009 and 2010 fundamental CO_2 prices.
- High Energy Efficiency – This sensitivity includes the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented, this increased EE impacts resulted in approximately a 13% decrease in retail sales over the planning period.

Chart A.1 shows the CO_2 prices utilized in the analysis.

Chart A.1



For the Clean Energy Legislation, the Company also performed a sensitivity by lowering the ACP to $30/MWhr and increasing the renewable energy assumptions to lower the Company's need to purchase ACPs.

EXHIBIT

Georgia Power Company's Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants, and Updated Integrated Resource Plan

---

Docket No. 34218

August 4, 2011

SC\NRDC EXHIBIT 3

5. 2011 Unit Retirement Study

5.1 Introduction

Unit Retirement Study evaluations were performed for each Georgia Power coal unit that has not already incurred significant expenditures for environmental controls. For each of the analyses below (Sections 5.5.1-5.5.10), the Unit Retirement Study evaluated controlling or replacing the units in 2015 based on current expected compliance requirements and such analysis was used in the Company's decision to control, fuel switch, retire, or defer. For some of the units recommended for deferral that would not be able to be controlled in time for a 2015 Utility MACT compliance date, an additional analysis was conducted to determine the potential impacts of adding controls equipment at a later date. This additional analysis assumed that such units would be unavailable from 2015 until the projected date by which the required controls could be installed. For Plant Hammond Units 1-3, an additional analysis was conducted assuming a one year extension is granted under Utility MACT for Hammond as discussed in Section 2.3.4. The set of controls assumed for each unit varies based on what controls are currently expected to be required for compliance with current and future environmental rules and regulations. At the top of each table, there is a list of the controls included in the analysis along with the year in which the control is assumed to be applied for purposes of the analysis.

The incremental cost of the controlled coal unit was compared to a proxy represented by site-specific replacement capacity cost. The evaluation included hourly production cost modeling and cost implications to the transmission system. Changes in production cost, capital, and other fixed costs were captured in the comparison to help determine the most economical option.

5.2 Incremental Costs

Incremental costs include fuel, operation and maintenance ("O&M"), capital, and emissions costs (NO_X, SO_2, and CO_2) associated with continued operation of the facility. An economic dispatch model provided annual fuel costs and emissions costs based on the hourly operation of the unit in each scenario for the years 2011 to 2040.

O&M includes labor, materials, overhead costs, and the costs of engineering and support services requested by the plant. Five-year projections of unit incremental O&M costs were obtained from the 2011 budget process. The incremental costs for the remaining years (2015 to 2040) were calculated using a moving average of the projections for the first 5 years and escalating the resulting value at inflation. Environmental O&M for all scheduled environmental controls is also included.

The incremental capital costs for each unit for years 2011 to 2040 were based on capital expenditures projected by each generating plant. These projected capital expenditures were necessary to keep the units running through the analysis period at the current level of operation.

Environmental control capital expenditures that could be required for compliance were not included in the capital expenditures provided by individual plants. Instead, these incremental capital estimates were provided by Southern Company Services ("SCS") Engineering and Construction Services ("E&CS"). The most recently available capital estimates were used in the studies and were included as specified in the analyses below. The control requirements and dates were based on the interpretation of the combination of currently final, proposed, and/or expected environmental rulemakings and their associated compliance requirements. As these rules are finalized, some of these requirements and dates may shift; however, those included are based on the most recent knowledge and expectations at the time of the analyses.

Fixed costs associated with the continued operation for the existing generating units were based on projections of annual O&M and the net present value ("NPV") of the revenue requirements associated with incremental capital investment necessary to keep the unit operational over the 30-year evaluation period.

5.3 Replacement Costs

Replacement costs, installation capital, fixed O&M, and continue to operate capital are all site specific and developed by SCS E&CS. In addition, individual transmission cost implications of the retirement and replacement were estimated by SCS Transmission.

For the unit retirement studies, most coal units were compared to a proxy represented by the expected cost of a CC at [redacted] This was judged to be the best site in Georgia and was used for comparison on the Plant Branch, Plant Yates and Plant Hammond studies. For the units where fuel was switched to gas with oil backup (Plants Kraft, McIntosh and McManus), a comparison was made to a proxy represented by the expected cost of a site-specific CT. In all comparison studies except Plant Mitchell Unit 4C, the costs of a megawatt ratio portion of the replacement unit was used. For example, if the study looked at replacing 500 MW of coal generation, the costs for a 500 MW portion of a [redacted] MW CC would be used for the comparison.

For Plant Mitchell Unit 4C, because the unit is a small CT that is used exclusively for peaking capacity, the unit was not compared to a replacement CC or CT but instead was compared to a more generic replacement capacity cost.

Replacement energy costs were estimated using the Southern Electric System marginal replacement costs for both continued coal operation and the replacement alternative. Marginal replacement costs were generated with the Pro-Sym® model over a 30-year period (2011 to 2040). The marginal replacement costs were then used to dispatch both the coal unit and the replacement units. The energy benefits (marginal replacement costs minus variable operating costs) were compared to determine the commitment and energy value to the Southern Electric System for both generating options. The net present value of the difference between replacement cost and unit operational cost was calculated to determine the overall net contribution.

In Appendix C Table C.3, the NPV of the revenue requirements for the various components of the replacement generation are provided for each set of coal units studied. These components are included in the calculations for which results are shown in Sections 5.5.1-5.5.10. The NPV of revenue requirements for the controls for each coal unit is provided in Appendix C Table C.2.

5.4 Scenarios

Uncertainty is a challenge for planning. The Company works to manage this challenge by considering multiple different future outcomes in key areas of uncertainty, including future CO_2 control requirements and future natural gas supply. The Company formally analyzes multiple scenarios, each of which adopts a particular view of future CO_2 control and a particular view of future natural gas supply.

With its modeling analysis consultant, Charles River Associates ("CRA"), the Company developed four possible CO_2 control requirement futures and three possible natural gas supply futures. The scenarios created by the combination of these CO_2 and natural gas supply price futures were developed to represent the range of plausible outcomes. Each of the twelve scenarios provides an internally-consistent view of fuel and electricity markets in the US. For each of these scenarios, the Company has performed the detailed asset valuation analysis for each unit discussed in this filing.

Four future CO_2 control scenarios were considered. Each was defined by a different future path of the price of CO_2. The four paths each start in 2015 at $0, $10, $20 and $30 per metric ton of CO_2 (2008$). On each path (except $0), the price increases at [redacted]% annually above inflation. These CO_2 price levels were chosen to span the plausible short term and long term range of CO_2 requirements when considering multiple factors, including US economic impact and likely cost-containment provisions.

Three future natural gas supply scenarios were considered. They largely reflect different views about the future supply of shale and other domestic US natural gas, from relatively plentiful to relatively scarce. Future natural gas demand scenarios were considered. They largely reflect different views about the amount of natural gas-fired generation in the U.S. and consumer and business demand for natural gas. These result in three different price futures for US natural gas, from relatively low to relatively high. These three fuel price scenarios assume long-term supply and demand market equilibrium. In recognition of the normal supply and demand imbalances that actually occur regularly in the natural gas market, the Moderate fuel case also considers volatility surrounding natural gas prices and it reflects recent historic market imbalances price impacts.

Future events related to domestic and global supply and demand may occur within the fuel markets that could result in a range of future price regimes, most importantly in the natural gas markets. These events may or may not be related to ongoing debates within the regulatory or legislative environment, but reflect potential for ranges of fuel supply such as the amount of domestic conventional and unconventional gas (primarily shale gas) available as well as the amount of imports into the U.S., including Liquified Natural Gas ("LNG") and Alaska gas. Therefore, natural gas resource assumptions have been developed describing three scenarios that result in Low, Moderate and High natural gas price forecasts. In addition, supply/demand relationships between coal, oil, and natural gas are reflected within each scenario such that a change in one of these markets impacts the others within the scenario.

The modeling system that CRA employs for the Company's analyses (MRN-NEEM) is a sophisticated, multi-sector dynamic general equilibrium model of the US economy that takes into account supplies and demands for all goods and services in the economy, focusing on the markets for energy and energy-intensive goods and services--especially electricity. The model finds price paths in all markets so that the quantity supplied is equal to the quantity demanded. All of these markets must be considered to generate a fully integrated view in each scenario.

In each scenario, the modeling captures shifts in generation investment choices through retirements of existing capacity (primarily base load coal), installation of new GHG control technologies, and the construction of new replacement capacity. Higher CO_2 and fuel costs generally increase electricity prices and reduce overall US economic activity, therefore, decreasing growth in electricity sales. All of these interrelated factors, including reductions to load growth, are considered in the Company's scenario modeling process.

The detailed asset evaluations also incorporated the twelve fully integrated scenarios in order to capture variations in the operating environments that may affect the retirement of the units. The detailed analyses included the implications of the addition of the following environmental controls where they were deemed to be required: scrubber ("FGD"), SCR, baghouse, potential SNCR, potential CCR regulation costs, scrubber wastewater treatment and compliance with proposed 316(b) regulations.

5.5 Summary of Study Results

The following tables (Sections 5.5.1-5.5.10) present the NPV customer cost results for the comparison of costs of the appropriate replacement proxy unit minus the cost to continue to operate each set of coal units with the controls listed for that particular unit. When a positive value is given for a scenario, there is a net additional cost to the customer for replacement generation and controlling the coal unit is therefore the better economic option. When there is a negative number for a scenario, there is a greater cost to the customer in controlling the coal unit and replacing the coal unit is therefore the better option. Appendix C summarizes the environmental costs applied to each of the controlled coal units. Table C.1 provides the in-service cost of the individual environmental controls. In Table C.2, the NPV of the declining revenue requirements ("DRR") for each of these controls is provided. If the analysis was to be examined without a particular environmental control that *was* included in the results given in Sections 5.5.1-5.5.10, the NPV of the DRR for that particular control could be added back to each scenario. Conversely, if there is an additional required control that was *not* included in the results in Sections 5.5.1-5.5.10, the NPV for the DRR for that control would be subtracted from each cell in the matrix.

Appendix D summarizes the costs and benefits of continued operation for each set of coal units for the \$0 CO_2 – Moderate Fuel case over the 30-year period (2011-2040).

5.5.1 Plant Branch Units 1 & 2

__2015 Compliance Results__

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is in accordance with the original Multipollutant Rule dates of December 31, 2014 for Branch 1 & 2.

Table 5.1

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	[redacted]	[redacted]	[redacted]	[redacted]
Moderate	[redacted]	[redacted]	[redacted]	[redacted]
Low	[redacted]	[redacted]	[redacted]	[redacted]

In this analysis, the assumed costs include compliance with the Georgia Multipollutant Rule (scrubber and SCR), and anticipated controls under the Utility MACT (baghouse), compliance with EPA's CCR Rule, new effluent guidelines (wastewater treatment), and 316(b) rule (intake structure). Note that a cooling tower was not included in the Plant Branch Units 1 & 2 analysis. The cost for this control is included in Appendix C. Depending on the severity of the 316(b) regulations, the upgrades to the intake structures may be sufficient or a closed cycle cooling tower may be required. Based on the proposed rule, it is expected that a cooling tower would not be required, and therefore costs have not been included. Included in the 316(b) costs is a new intake structure with 20 fine mesh screens with fish returns across the inlet from Little River. These would be required for Plant Branch Units 1 & 2 or Units 3 & 4, regardless of the operation of the other two units and have been included in the analysis.

5.5.2 Plant Branch Units 3 & 4

2015 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2015 Scrubber ~ 2015 SCR ~ 2015 Baghouse ~ 2016-2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, the scrubber, SCR and baghouse were online at the beginning of 2015. Note that this 2015 compliance is prior to the new Multipollutant Rule dates of late 2015 for Branch 3 & 4.

Table 5.2-a

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	[redacted]	[redacted]	[redacted]	[redacted]
Moderate	[redacted]	[redacted]	[redacted]	[redacted]
Low	[redacted]	[redacted]	[redacted]	[redacted]

2016 Compliance Results

Customer Costs for Replacement CC Proxy Relative to the Cost of Continued Operation

NPV (2011-2040) in Millions of Dollars

- In-Service Dates of Environmental Controls included on the coal units:

2016 Scrubber ~ 2016 SCR ~ 2016 Baghouse ~ 2016-2017 CCR ~ 2018 Scrubber Wastewater Treatment ~ 2018 Intake Structures

- For the purposes of this analysis, Plant Branch Units 3 & 4 were assumed to be unavailable in 2015 due to required controls not being installed in time to meet anticipated compliance requirements.

Table 5.2-b

Fuel/CO_2	\$0 CO_2	\$10 CO_2	\$20 CO_2	\$30 CO_2
High	[redacted]	[redacted]	[redacted]	[redacted]
Moderate	[redacted]	[redacted]	[redacted]	[redacted]
Low	[redacted]	[redacted]	[redacted]	[redacted]

For both analyses, the assumed costs include compliance with the Georgia Multipollutant Rule (scrubber and SCR), and anticipated controls under the Utility MACT rule (baghouse), compliance with EPA's CCR Rule, new effluent guidelines (wastewater treatment), and 316(b) rule (intake structure). Note that a cooling tower was not included in the Plant Branch Units 3 & 4 analysis. The cost for this control is included in Appendix C. Depending on the severity of the 316(b) regulations, the upgrades to the intake structures may be sufficient or a closed cycle cooling tower may be required. At this time, it is expected that a cooling tower will not be required, and, therefore, costs have not been included. Included in the 316(b) costs is a new intake structure with 20 fine mesh screens with fish returns across the inlet from Little River.

These would be required for Plant Branch Units 1 & 2 or Units 3 & 4, regardless of the operation of the other two units and have been included in the analysis.

EXHIBIT

215

PUBLIC VERSION

TO THE
PUBLIC UTILITIES COMMISSION OF OHIO

DUKE ENERGY OHIO, INC.
2011 ELECTRIC
LONG-TERM FORECAST REPORT
AND RESOURCE PLAN

CASE NO. 11-1439-EL-FOR

SC\NRDC EXHIBIT 4

STATEMENT
OF
JULIA S. JANSON
PRESIDENT, DUKE ENERGY OHIO, INC.

I, Julia S. Janson, President of Duke Energy Ohio, Inc., hereby certify that the statement and modifications set forth in the 2011 DUKE ENERGY OHIO LONG-TERM ELECTRIC FORECAST REPORT AND RESOURCE PLAN as submitted to the Public Utilities Commission of Ohio are true and correct to the best of my knowledge and belief.

I further certify that the requirements of Ohio Administrative Code §4901:5-1-03, paragraphs (F) to (I) will be met.

Julia S. Janson
President
Duke Energy Ohio, Inc.

Libraries Receiving a Letter of Notification Regarding Duke Energy Ohio, Inc.'s 2011 Long-Term Forecast Report and Resource Plan

County	Library	Address
Adams	Manchester Branch Library	401 Pike St. Manchester, Ohio 45144
Brown	Mary P. Shelton Library	200 West Grant Avenue Georgetown, Ohio 45121
Butler	Lane Public Library	300 North Third Street Hamilton, Ohio 45011
Butler	Middletown Public Library	125 South Broad Street Middletown, Ohio 45044
Clermont	Clermont County Public Library	180 South Third Street Batavia, Ohio 45103
Clinton	Wilmington Public Library	268 North South Street Wilmington, Ohio 45117
Hamilton	Public Library of Cincinnati and Hamilton County University of Cincinnati Library Reference Division	800 Vine Street Cincinnati, Ohio 45202 2600 Clifton Avenue Cincinnati, Ohio 45221
Highland	Highland County District Library	10 Willettsville Pike Hillsboro, Ohio 45133
Montgomery	Dayton and Montgomery County Public Library	215 East Third Street Dayton, Ohio 45402
Preble	Preble County District Library	301 North Barron Street Eaton, Ohio 45320
Warren	Lebanon Public Library	101 South Broadway Lebanon, Ohio 45036

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of Duke Energy Ohio's Long-Term Forecast Report and Resource Plan was served by hand delivery, this 15th day of July, 2011 upon the following:

Office of the Ohio Consumers' Counsel

10 West Broad Street, Suite 1800

Columbus, OH 43215-3485

Furthermore, a Letter of Notification was sent by First Class U.S. Mail to each library listed in the Report.

Elizabeth H. Watts
Associate General Counsel
Duke Energy Business Services

TABLE OF CONTENTS

Page

L. SYSTEM OPTIMIZER RESOURCE PORTFOLIO ALTERNATIVES

The SO capacity expansion model was used to develop alternative resource portfolios through 2020. There was not a significant difference between the EE economic potential and the requirements associated with SB 221 by 2021. Therefore, only the requirements associated with SB 221 were considered in SO portfolio development. Also, though it is the Company's belief that there will be a carbon-constrained future, the likelihood of legislation being passed prior to 2013 is unlikely. With the uncertainty of federal climate change legislation with regard to greenhouse gas reduction, Duke Energy Ohio has established a CO_2 price curve beginning in 2016 to represent the potential for future federal climate change legislation. The CO_2 prices that Duke Energy is utilizing are associated with proposed and debated legislation, including H.R. 2454 – the American Clean Energy and Security Act of 2009, which passed the U.S. House of Representatives on June 26, 2009. The prices utilized in the 2011 Resource Plan represent the lower end of the range of prices that were estimated in proposed legislation. The projected CO_2 allowance prices are less than $20/ton by 2020 and it is not likely that prices would be higher in the short-term. For this reason, portfolios were not evaluated for variation in CO_2 prices. The primary focus of the resource plan was to determine how best to meet the capacity and energy needs in the 2015 period while positioning the Company to meet AER requirements when fully implemented by 2025.

Sensitivities in load, fuel, and the associated energy prices were evaluated to determine the basis for the different portfolios to be further evaluated in detailed production costing analysis. These portfolios are outlined in Table 4 L.1 below.

Table 4 L.1

Resource Portfolio Alternatives (2012 – 2020)		
	CT and CC Resources	RPS Renewables
CT Portfolio	1,050 – 2,100 MW Peaking PPA and/or Resources	28 MW new build Solar 350 MW new build Wind
CC/CT Portfolio	1,050 – 1,450 MW Peaking Resource 650 MW CC in 2015	28 MW new build Solar 350 MW new build Wind

The capacity need between 2012 and 2015 averages approximately 1,360 MW per year in addition to capacity that the legacy generation assets will still serve. This need will be met through the Company's FRR plan to meet the 15.3% reserve margin. The capacity need will increase in the 2015 period to 2,261 MWs primarily due to the retirement assumption of Beckjord Units 1-6 (859 MWs). The 2015 timeframe could be volatile time in the capacity market due to the significant number of coal retirements expected due to the new environmental regulatory requirements. Nationwide estimates of retirements of coal generation in the 2015 timeframe fall in the range of 40 to 80 GWs. Depending on the rate of economic recovery and the impact on load growth, adoption rates of DSM, and the number of retired coal units, there could be a capacity shortage in the 2015 timeframe. For this reason, the option of continued operation of and investment in the existing system, coupled with self- build or peaking or intermediate resource purchases is maintained to reduce the risk of exclusively relying on the capacity market to customers.

M. RESOURCE PORTFOLIO ALTERNATIVE EVALUATION RESULTS

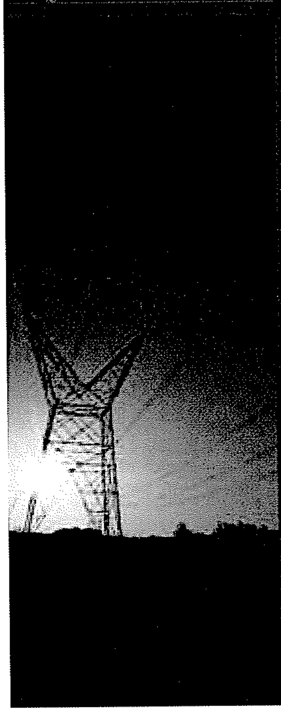
After the development of the alternative resource portfolios in SO, the PAR model was used to perform detailed production costing analysis for the CT Portfolio and the CC/CT Portfolio under the Proposed ESP construct for future resource needs.

EXHIBIT

Integrated Resource Plan

TVA's Environmental & Energy Future

March 2011

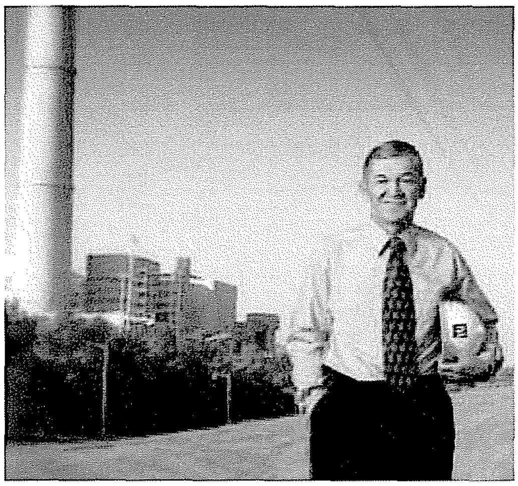


SC\NRDC EXHIBIT 5

Message from the CEO

TVA operates one of the largest power systems in the United States. With a generating capacity of more than 34,000 megawatts, we meet the daily electricity needs for an 80,000-square-mile region where more than 9 million people live, work and go to school. That's an enormous responsibility, and one we take very seriously.

A power system large and reliable enough to handle that responsibility doesn't come about by accident. It's the culmination of work by thousands of skilled professionals, and it all starts with focused and detailed planning.



Planning a power system is complex work that involves hundreds of variables, such as consumer trends, fuel and material costs, regulations, technology advancements and the weather. It's complicated even further by the need to forecast needs and conditions decades into the future.

TVA's new integrated resource plan is a critical part of our overall planning effort. It is a comprehensive study of options and strategies and their potential economic and environmental outcomes. The plan was shaped by input from the businesses, industries and regional leaders, as well as ordinary people, whose lives and livelihoods depend on the electricity supplied by TVA. The result of this two-year exercise gives us a sound basis for making better long-term decisions.

In addition, our integrated resource plan will help us fulfill TVA's renewed vision to become one of the nation's leading providers of low-cost and cleaner energy by 2020. The options that have been identified from this process involve reducing TVA's reliance on coal, increasing our supply of nuclear and renewable energy, and working in partnership with local utilities and the people they serve to use energy more efficiently.

Like most things, the cost of electricity is not likely to stay flat in the years ahead. Our challenge will be to keep power affordable while carrying out our vital work with the least impact on the environment today and for future generations.

Tom Kilgore

Tom Kilgore

Table of Contents

3 Public Participation

TVA is the largest public power company in the nation. An objective of this IRP was to understand the needs of the people it serves and how to address those needs in a cost-effective, reliable manner. Since the needs of the people vary, some people are more concerned about the cost of power, some on reliability, while others are concerned about environmental impacts. Therefore, it is TVA's ultimate responsibility to balance these competing needs as it plans for the future.

A transparent and participatory approach was utilized in the development of this IRP. Many opportunities were available to the public that influenced the development – and ultimately the outcome – of this IRP. For example, public briefings and meetings were held across the region, and an advisory review group was created. The following key objectives of public involvement were:

- Engage numerous stakeholders with differing viewpoints and perspectives throughout the entire IRP process
- Incorporate public opinions and viewpoints into the development of the IRP, including activities and opportunities for stakeholders to review and comment on various inputs, analyses and options considered
- Encourage open and honest communication in order to facilitate a sound understanding of the process
- Provide multiple communication channels to provide several ways for members of the public to learn about the IRP process and to provide input

TVA involved the public in each critical step of the IRP process. The involvement helped TVA identify the most effective ways to serve the people of the Tennessee Valley region. Public participation was actively solicited three times during the IRP process.

1. Public scoping period
2. Analysis and evaluation period
3. Draft IRP public comment period

3.1 Public Scoping Period

Public Comment Process:

Step 1 - Public Scoping Period

- Public Meetings
- Written Comments
- Scoping Questionnaire

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

The TVA IRP process began with a 60-day public scoping period June 15, 2009. TVA announced the start of the process in newspapers throughout the region via media releases and on TVA's website.

In addition, the EPA published the official EIS Notice of Intent in the Federal Register. This notice is required by the NEPA guidelines which require federal agencies such as TVA to prepare an EIS whenever its actions, such as the development of an IRP, have the potential to affect the environment.

During the scoping period, TVA disseminated a broad range of information to the public, including the reasons for developing an IRP, what it would focus on, the process for how an IRP is developed and how the results will be used to guide strategic decision making. Public scoping provided an early and open process to ensure:

- Stakeholder issues and concerns were identified early and properly studied
- Reasonable alternatives and environmental resources were considered
- Key uncertainties that could impact costs or performance of certain energy resources were identified
- Input received was properly considered and would lead to a thorough and balanced final IRP

TVA also reiterated the need to have a balanced approach when considering the tradeoffs of one energy resource for another. While developing this IRP, TVA sought public input on a variety of issues and asked the following questions:

- How will any changes affect system reliability and the price of electricity?
- Should the current power generation mix (e.g., coal, nuclear power, natural gas, hydro, renewable) change?

- Should energy efficiency and demand response be considered in planning for future energy needs?
- Should renewables be considered in planning for future energy needs?
- How can TVA directly affect electricity usage by consumers?

The scoping period helped shape the initial development and framework of this IRP. TVA used the input received to determine what resource options should be considered to meet future demand. TVA used two primary techniques, public meetings and written comments, to collect public input during the scoping period.

3.1.1 Public Meetings

During the scoping period, TVA held seven public meetings across the Tennessee Valley between July 20 and Aug. 6, 2009 (Figure 3-1). The meetings were conducted in an informal, open house format to give participants an opportunity to express concerns, ask questions and provide comments. Exhibits, fact sheets and other materials were available at each public meeting to provide information about the Draft IRP and the associated EIS.

Date	Location
July 20, 2009	Nashville, Tenn.
July 21, 2009	Chattanooga, Tenn.
July 23, 2009	Knoxville, Tenn.
July 28, 2009	Huntsville, Ala.
July 30, 2009	Hopkinsville, Ky.
Aug. 4, 2009	Starkville, Miss.
Aug. 6, 2009	Memphis, Tenn.

Figure 3-1 – Public Scoping Meetings

Attendees included members of the general public, representatives from state agencies and local governments, TVA's congressional delegation representatives, distributors of TVA power, non-governmental organizations and other special interest groups.

Approximately 200 attended the public scoping meetings. TVA subject-matter experts attended each meeting to discuss issues and respond to questions about the IRP planning process and TVA's power system and programs.

3.1.2 Written Comments

During the scoping period, TVA accepted comments via email, fax, letters, TVA's website, public scoping meetings and a scoping questionnaire. At the public scoping meetings, verbal comments were recorded by court reporters and attendees were able to submit written comments by logging onto TVA's website using TVA supplied computers.

Overall, TVA received approximately 1,000 comments from the following communication tools:

- Scoping questionnaire
- Email
- TVA's website
- Public meetings

Comments were received from four federal agencies and 20 state agencies representing six of the seven TVA region states. Some of these responses included specific comments, while others stated they had no comments, but asked to review the Draft IRP and the associated EIS. Figure 3-2 shows the distribution of scoping comments by geographic area.

Some agencies, organizations and individuals provided comments specific to TVA's natural and cultural resource stewardship activities. These comments were not included in the scoping report because they focused on another planning process – TVA's Natural Resource Plan (NRP) and associated EIS. The full scoping report on this IRP as well the NRP can be found on TVA's website.

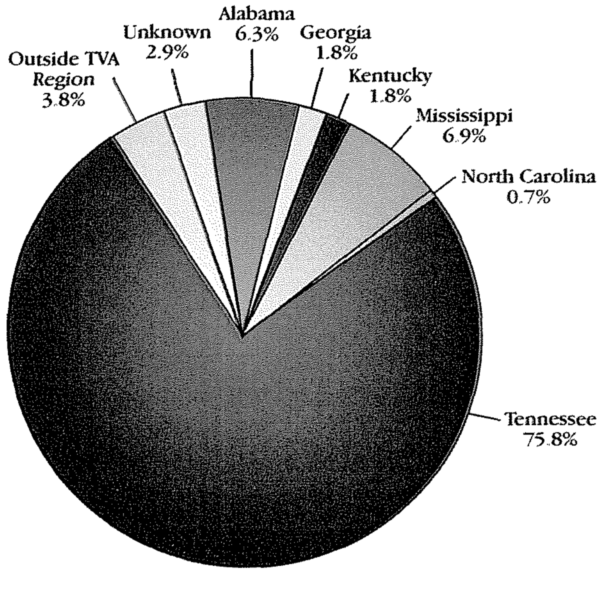


Figure 3-2 – Distribution of Scoping Comments by Geographic Area

3.1.3 Scoping Questionnaire

An 11-part scoping questionnaire was distributed at public meetings and made available on TVA's website. The questionnaire was developed to elicit public opinion on TVA's future generation and efficiency options. At least part of the scoping questionnaire was completed by 845 people, and 640 of the respondents answered the write-in questions as well as the multiple-choice questions.

Many of those who completed the questionnaire expressed a willingness to take various measures to reduce their energy use or pay higher rates for cleaner energy. The willingness to undertake some measures increased with the availability of financial incentives.

After further analysis, the results of the questionnaire indicated that the findings were not statistically significant and the survey population was not fully representative of the entire Tennessee Valley region. Therefore, TVA decided to conduct a phone survey of approximately 1,000 individuals across the entire region in the summer of 2010.

3.2 Analysis and Evaluation Period

The analysis and evaluation period took key themes and results identified from the scoping period and developed the framework for analysis and evaluation. The findings were considered when TVA developed the range of strategies for IRP analysis.

During this phase, TVA used the following three techniques to collect public input:

1. Stakeholder Review Group
2. Public briefings
3. Phone survey

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

- Stakeholder Review Group
- Public Briefings
- Phone Survey

Step 3 - Draft IRP Public Comment Period

3.2.1 Stakeholder Review Group

Early in the IRP process, TVA recognized it would be difficult to get specific and continuous input from the public beyond the scoping period. To obtain more in-depth, ongoing input from the public, TVA established an advisory Stakeholder Review Group (SRG) in July 2009.

The formation of this diverse 16-member review group (listed on page 42) was the cornerstone of the public input process. It consisted of representatives from business and industry, state agencies, government, distributors of TVA power, academia, special interest groups and civic organizations. In addition to providing their individual views to TVA, SRG members represented their constituency and reported to them on the IRP process.

The SRG met approximately every month with TVA. Ten meetings were held prior to the release of the Draft IRP and the associated EIS at various locations throughout the region. Five additional meetings were held between the release of the Draft IRP and approval of the Recommended Planning Direction to facilitate ongoing feedback and guidance for this IRP. Figure 3-3 shows the dates and locations of all the SRG meetings.

Date	Location
July 29, 2009	Nashville, Tenn.
Aug. 18, 2009	Knoxville, Tenn.
Sept. 24, 2009	Chattanooga, Tenn.
Oct. 22 & 23, 2009	Chattanooga, Tenn.
Dec. 10 & 11, 2009	Nashville, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.
June 29, 2010	Murfreesboro, Tenn.
July 20 & 21, 2010	Chattanooga, Tenn.
Aug. 12, 2010	Chattanooga, Tenn.
Aug. 26, 2010	Chattanooga, Tenn.
Oct. 28, 2010	Knoxville, Tenn.
Nov. 18, 2010	Murfreesboro, Tenn.
Dec. 15, 2010	Chattanooga, Tenn.
Jan. 26, 2011	Knoxville, Tenn.
Feb. 24, 2011	Chattanooga, Tenn.

Figure 3-3 – Stakeholder Review Group Meetings

The meetings were designed to encourage dialogue on all facets of the IRP process, and to facilitate information sharing, collaboration and expectations for this IRP. Topics included energy efficiency best practices, TVA's power delivery structure, load and commodity forecasts and supply resource options.

The individual views of SRG members were collected on the entire range of assumptions, analytical techniques and proposed energy resource options and strategies. Given the diverse makeup of the SRG, there were a wide range of views on specific issues, such as the value of energy efficiency programs, environmental concerns and the appropriateness of some new technologies. Open discussions supported by the best available data facilitated better comprehension of the specific issues.

To increase public access and transparency to the IRP process, all non-confidential SRG meeting material (i.e., presentations, agenda and minutes) was posted on TVA's website. In addition, TVA developed an internal website specifically for SRG members to post information on and to request data from TVA staff.

3.2.2 Public Briefings

In addition to the public scoping and SRG meetings, TVA held four public briefings (Figure 3-4). The public briefings informed the general public of the IRP process.

Date	Location
Oct. 23, 2009	Chattanooga, Tenn.
Nov. 16, 2009	Chattanooga, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.

Figure 3-4 – Public Briefings

Participants had the option to attend in person or by webinar. The format of the public briefings included a brief presentation followed by a moderated Q&A session with the audience.

Topics discussed at the public briefings included an overview of the integrated resource planning process, resource options, development of scenarios and strategies and evaluation metrics.

The public briefings attendance averaged 15 to 20 in-person participants and approximately 30 to 40 participants by webinar. Videos of the briefings and presentation materials were posted on the IRP project website.

TVA also briefed the public on the IRP process through presentations given at local organizations, clubs and associations including the following:

- Association of Energy Engineers
- Tennessee Renewable Energy and Economic Development Council
- Chattanooga Engineers Club
- City of Chattanooga
- Chattanooga Green Spaces
- EPRI Environmental Aspects of Renewable Energy Interest Group Workshop
- Clean Energy Speakers Series at Georgia Tech
- Howard H. Baker, Jr. Center for Public Policy
- Technical Society of Knoxville

3.2.3 Phone Survey

To ensure an even wider representation of opinions on IRP choices were considered, TVA partnered with Harris Interactive to develop a statistically representative phone survey of approximately 1,000 Tennessee Valley residents. The customer phone survey was conducted during June and July 2010 for the following reasons:

- Determine primary power generation concerns among the Tennessee Valley residents (i.e., cost, reliability, use of renewables, etc.)
- Determine market potential for voluntary and financially incentivized energy efficiency programs
- Determine market potential of renewable programs, including Green Power Switch® and other existing or planned energy efficiency and demand response programs
- Estimate potential market pricing for renewable power programs, including the additional amounts Tennessee Valley residents are willing to pay each month for energy from renewable sources
- Assess Tennessee Valley residents' attitudes of and satisfaction with TVA, including analysis of the services that it provides to the Tennessee Valley

Survey results indicated that the Tennessee Valley residents have a favorable attitude of TVA, consider system reliability a critical component of utility services and want to see TVA focused on keeping prices affordable.

Key findings included:

TVA quality of service	• 94 percent of respondents agreed that providing a reliable supply of electricity is very important in assessing TVA's quality of service • 92 percent indicated that keeping electricity rates affordable is important
Meeting future energy needs	• 70 percent of respondents also deemed it very important for TVA to reduce air pollutants and emissions

Renewable energy	• 42 percent of respondents believed that adding different energy sources, such as solar and wind, into TVA resource portfolio should be emphasized the most to meet future energy needs
	• 42 percent of respondents indicated they likely would pay more for renewable energy, with the following breakdown:
	  • Those indicating they would definitely pay more would pay an average of $12.60 per month to ensure that 10 percent of their energy comes from renewable sources
	  • This same group would pay an average of $26.91 more per month to ensure that all of their energy is renewable
	  • Tennessee Valley residents indicating they would definitely or probably pay more were willing to pay $11 to $20 per month to reduce CO_2 emissions
	  • Opportunities exist for additional Green Power Switch® awareness among Tennessee Valley residents

Biggest concerns related to electricity production	• Cost and billing • Environmental impact • Quality of power supply

3.3 Draft IRP Public Comment Period

After the Draft IRP was completed in the fall of 2010, TVA provided an opportunity for the public to provide comments and give input. Following the Sept. 15, 2010 publication of the Draft IRP with EPA, a 52-day comment period was provided to solicit input about the Draft IRP from the public.

Originally set to close Nov. 8, 2010, the 45-day comment period was extended an additional seven days to accommodate several external stakeholders' requests. For this phase of the IRP process, TVA presented the results to both internal TVA stakeholders and the general public in the Draft IRP and the associated EIS.

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

- Public Meetings
- Webinars
- Written Comments

TVA used the following three techniques to collect input during the Draft IRP:

1. Public meetings
2. Webinars
3. Written comments

3.3.1 Public Meetings

TVA had five meetings with the public across the Tennessee Valley region in October 2010 (Figure 3-5). These meetings gave the public an opportunity to present their views on the Draft IRP to TVA leadership and subject-matter experts.

Date	Location
Oct. 5, 2010	Bowling Green, Ky.
Oct. 6, 2010	Nashville, Tenn.
Oct. 7, 2010	Olive Branch, Miss.
Oct. 13, 2010	Knoxville, Tenn.
Oct. 14, 2010	Huntsville, Ala.

Figure 3-5 – Public Comment Period Meetings

TVA publicized the meetings and webinars by placing advertisements in major newspapers and issuing news releases prior to each meeting that many local newspapers carried. Before each of the meetings, TVA met with local reporters in each location who frequently write about TVA and the IRP process so that they, in turn, could write articles to help the public understand the IRP process and draft document.

Online advertising (i.e., announcements on TVA's Facebook page) was used to reach an even wider audience. TVA's website was also regularly updated with the latest news regarding the IRP process and logistics for each public meeting.

At each of these meetings, TVA presented an overview of the Draft IRP followed by a moderated Q&A session supported by a panel of TVA subject-matter experts. Attendees were able to address comments or questions to the panel. Attendees also had the option to submit written and verbal comments to a court reporter before or after the presentations. A transcript and video of each meeting was recorded. The presentation slides and video of the meeting in Bowling Green, Ky., and videos of each Q&A session were posted on the TVA's website.

TVA encouraged comments from the public on the Draft IRP and the associated EIS. Comments received enabled TVA staff to identify public concerns and recommendations concerning the future operation of the TVA power system. The public comments and TVA's responses are included in the associated EIS.

3.3.2 Webinars

To encourage as much participation as possible, members of the public who were not able to attend public meetings were able to participate by webinar. Attendees registered in advance and were able to access the presentation and participate in the Q&A session from personal computers.

3.3.3 Written Comments

During the 52-day public comment period, comments were submitted via TVA's website, email, U.S. mail and fax. Comments and questions recorded at each of the public meetings were also considered.

In all, TVA received approximately 500 responses from a multitude of individuals, organizations and agencies. These responses contained 748 comments of which 372 were unique and addressed in the associated EIS. A general summary of unique comments received during the public comment period on the Draft IRP can be seen in Figure 3-6.

Method of Comment	Number Received
Email	38
Online comment form	104
Webinar comment/question from IRP meetings	16
Oral comment/question from IRP meetings	30
Letters	16
Form Letters (pre-printed post cards)	297
Total	501

Figure 3-6 – Type of Responses Submitted

The following organizations and agencies submitted comments:

- Environmental Protection Agency
- Natural Resource Defense Council
- Southern Alliance for Clean Energy
- Sierra Club
- Earth Justice
- Distributors of TVA power
- State agencies
- Tennessee Valley Public Power Association
- Industry groups (i.e., solar energy, natural gas, etc.)

3.4 Public Input Received During the IRP Process

Public input received during the IRP process covered a wide spectrum of subjects. From public scoping to the comments received on the Draft IRP, the ongoing feedback assisted TVA in identifying the relevant concerns of the public with respect to resource planning. Input received during the IRP process also provided beneficial insight to common public perceptions of TVA programs and willingness to invest in certain resource options. For example, the SRG and public input encouraged TVA to consider larger renewable portfolio targets beyond current resource plans, resulting in consideration of portfolios of 2,500 and 3,500 MW.

Moreover, public input helped develop the framework for analysis and addressed a wide range of issues, including the cost of power, recommended resource options, the environmental impacts of different resource options and the integrated resource planning process. The following sections briefly summarize the issues raised with additional detail provided in the associated EIS.

Costs of New Capacity, Financing Requirements and Rate Implications

Concerns about the ability of TVA to design, build and deliver major new capacity on time and within budget were expressed. Questions about the validity of construction cost estimates for new nuclear capacity were raised.

The public also expressed concerns about TVA's ability to fund future resource additions due to the $30 billion limit on TVA's statutory borrowing authority. TVA's financing options to cover the costs of construction for major capital investments are limited to borrowing, increasing rates or other less traditional forms of financing. There were also concerns about potential impacts on short-term rates. However, some believed that higher rates may promote energy efficiency investments.

While a large number of people were opposed to any future price increases, a number of those who completed the scoping questionnaire expressed a willingness to pay $1-$20 more per month for TVA to increase generation from non-greenhouse gas emitting sources.

Recommended Energy Resource Options

The public made recommendations about TVA's future supply- and demand-side resource options. TVA's future resource portfolio should:

- Avoid or minimize rate increases
- Minimize or reduce pollution and other environmental impacts
- Maximize reliability
- Contain a diversity of fuel sources

The following resources options were mentioned:

Nuclear expansion	• Supported nuclear additions if implemented in a cost-effective, responsible way • Concerned with rising costs and nuclear waste issues related to additions to the nuclear portfolio
EEDR initiatives	• Pleased with the contribution of EEDR in the planning strategies retained in the Draft IRP • Comments regarding the target level of EEDR being studied and the potential for larger amounts of EE to displace new nuclear capacity • Uncertainty about cost, lost revenue impacts and program effectiveness; and questioned measurement and verification of benefits
Renewable additions	• Supported increased renewable generation (including wind, solar, locally-sourced biomass and low-impact hydro) as long as costs are competitive • Stated the need for a stronger commitment to developing renewables within the Tennessee Valley region, particularly solar, as opposed to imported wind power • Questioned system operational impacts caused by intermittent or off-peak resources (i.e., wind and solar)
Idling coal-fired capacity	• Commended TVA on the strategy for coal-fired capacity idling and to consider larger quantities of idled capacity • Concerned with the economic and environmental implications of idling certain coal-fired units • Concerned about TVA's risk exposure for pending carbon legislation and issues related to lead-time for positioning coal-fired assets for idling, retirement and/or return to service
Energy storage	• Recommended an increase in energy storage capability
Natural gas	• Supported additional natural gas-fired generation

Environmental Impacts of Power System Operations

A general concern about pollution was a frequently mentioned issue in regards to the TVA power system. Additionally, much of the public felt the issues with air pollutants, greenhouse gas emissions, climate change, spent nuclear fuel and coal combustion by-products were of high importance.

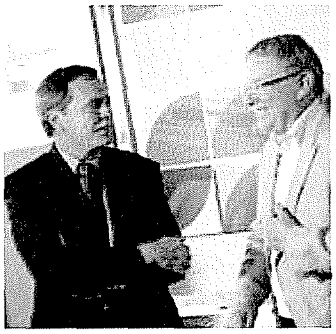
Many comments encouraged TVA to decrease its emissions of greenhouse gases while others questioned the human influence on climate change. The issue was also raised of the impacts of buying coal from surface mines, particularly mountaintop removal mines, and recommended that TVA stop this practice. The Kingston Fossil Plant ash spill in December 2008 was frequently mentioned.

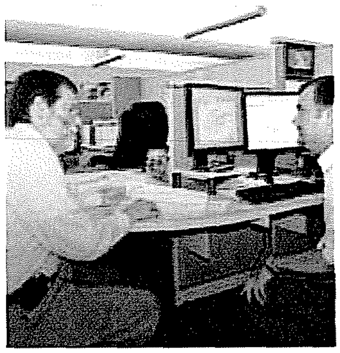
The Integrated Resource Planning Process

Several people addressed the IRP process. Their comments recommended that TVA continue to follow industry standard practices; enter the process without preconceptions about the adequacy of various resource options; be open and transparent throughout the planning process; treat energy efficiency and renewable energy as priority resources and address the total societal costs and benefits.

3.5 Response to Public Input and Comments

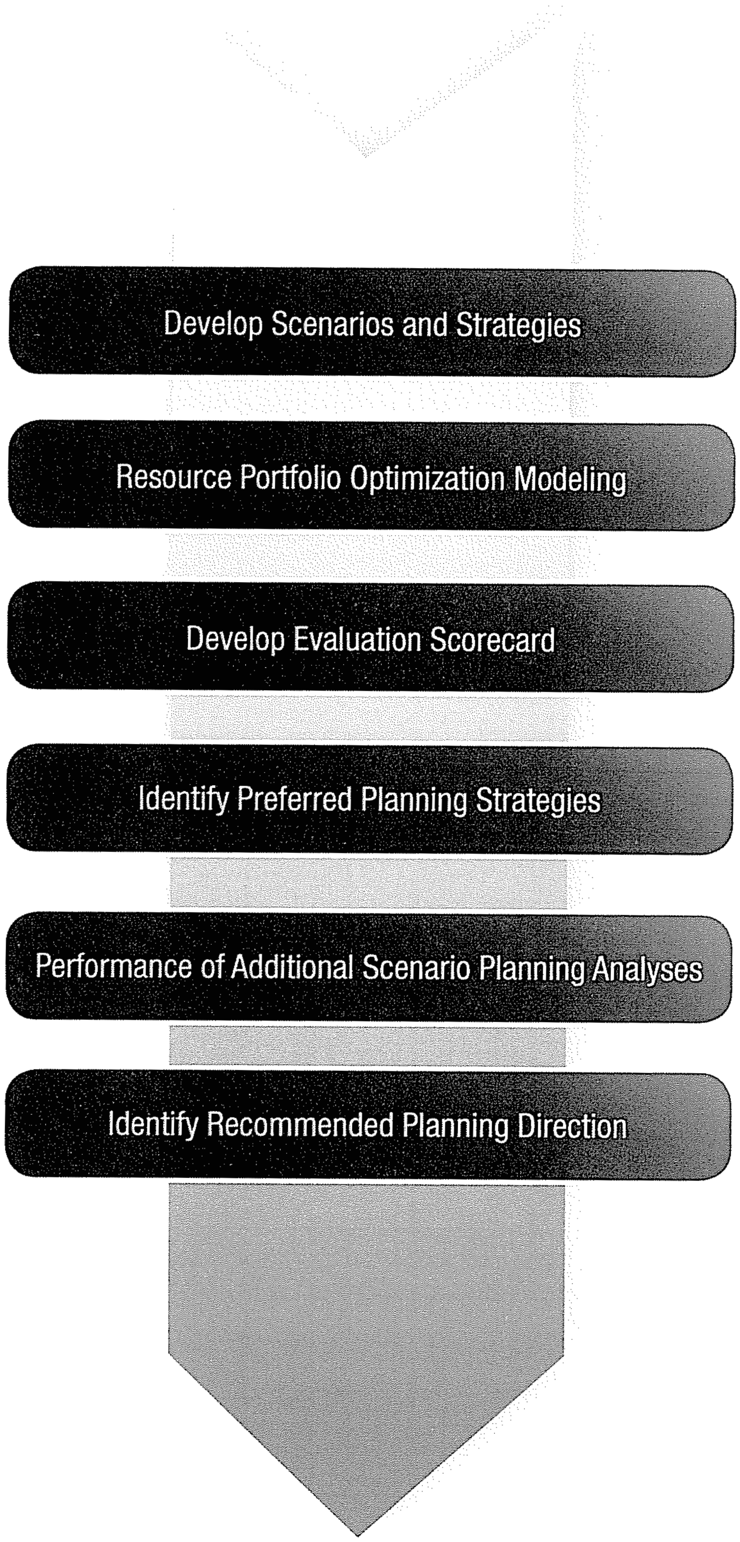
Input received from the general public and stakeholders was a key part of the IRP process. Listening to different stakeholders' perspectives, viewpoints and sometimes competing objectives played a prominent role in choosing a Recommended Planning Direction for TVA. Appendix F – Stakeholder Input Considered and Incorporated provides examples on how key themes were incorporated into the IRP analysis.





TVA's Integrated Resource Plan is a synthesis of public input and strategic planning and professional analysis.

Process for Identifying the Recommended Planning Direction



6 Resource Plan Development and Analysis

TVA employed a scenario planning approach in the development of the Draft and the final IRP. This approach is commonly used in the utility industry. The goal of this approach was to develop a "no-regrets" strategy that was relatively insensitive to uncertainty. In other words, once strategic decisions were made, the strategy would perform well regardless of how the future unfolds. The processes used in the scenario planning approach, including evaluation methods and strategy selection, are outlined in this chapter.

This chapter describes the following six steps of the Draft IRP process:

1. Development of the scenarios and strategies used to conduct the scenario planning analysis
2. Resource portfolios optimization modeling
3. Development of scenario planning scorecards to measure the performance of the portfolios and strategies developed in the scenario planning analysis
4. Identification of preferred planning strategies for publication in the Draft IRP
5. Incorporation of public input and performance of additional scenario planning analyses
6. Identification of the Recommended Planning Direction

6.1 Development of Scenarios and Strategies

Scenario planning is useful for determining how various business decisions will perform in an uncertain future. Multiple strategies, which represented business decisions that TVA can control, were modeled against multiple scenarios, which represented uncertain futures that TVA cannot control. The intersection of a single strategy and a single scenario resulted in a resource portfolio.[1] A portfolio is a 20-year capacity expansion plan that is unique to that strategy and scenario combination.

Modeling multiple strategies within multiple scenarios resulted in a large number of portfolios. Proper analysis of these portfolios was a challenge. Accordingly, during early stages of the analysis, it was more important to observe trends or common characteristics that strategies exhibited over multiple scenarios rather than focusing on specific outcomes in individual portfolios. If a strategy behaved in a similar manner in most scenarios, the modelers could be confident of its robustness. Characteristics of robustness included increased flexibility, less risk over the long term and the ability to mitigate the impacts of

[1]Portfolios are also referred to as capacity expansion plans or resource portfolios

uncertainty. Conversely, a strategy that behaved differently or poorly in each scenario that it was modeled within was considered more risky and indicated a higher probability for disappointment and future regret.

6.1.1 Development of Scenarios

Most quantitative models focus on what is statistically likely based on history, market data and projected future patterns. The scenarios developed for the planning approach operated differently by utilizing assumptions that the future evolves along paths not suggested by history. They were not assigned a probability that one particular future is more likely to occur than another. Using this approach, scenarios identified and framed plausible futures that were studied in the development of the long-range resource plan.

The following three-step process was used to develop scenarios used in this IRP:

1. Identification of key uncertainties
2. Development of scenarios
3. Determination of scenario uncertainty values

Scenarios represent future conditions that TVA cannot control but must adapt to.

Identification of Key Uncertainties

TVA, with input from the SRG, identified uncertainties that were used as building blocks to develop scenarios for this IRP. The key uncertainties are listed in Figure 6-1.

Key Uncertainty	Description
Greenhouse gas (GHG) requirements	• Reflects level of emission reductions (CO_2 and other GHG) mandated by federal legislation plus the cost of carbon allowances
Environmental outlook	Changes in regulations addressing: • Air emissions (exclusive of GHG) • Land • Water • Waste
Energy efficiency and RES	• Reflects mandates for minimum generation from renewables and the viability of renewable generation sources • It includes the percentage of the RES standard that can be met with energy efficiency
Total load	• Reflects variance of actual load to what is forecast • Accounts for benefits of EEDR penetration
Capital expansion viability & costs	For nuclear, fossil, other generation and transmission, includes risks associated with: • Licensing • Permitting • Project schedule
Financing	• Financial cost (interest rate) of securing capital
Commodity prices	• Includes natural gas, coal, oil, uranium and spot price of electricity
Contract purchase power cost	• Reflects demand cost, availability of power and transmission constraints
Change in load shape	Includes effects of factors such as: • Time-of-use rates • Plug-in Hybrid Electric Vehicles (transportation) • Distributed generation • Economics changing customer base • Energy storage • Energy efficiency • Smart grid / demand response
Construction cost escalation	Includes the following for nuclear, fossil and other generation: • Commodity cost escalation • Labor and equipment cost escalation

Figure 6-1 – Key Uncertainties

Development of Scenarios

Scenarios were constructed by utilizing various combinations of the key uncertainties in Figure 6-1. They were then further refined to ensure that the following characteristics for each scenario:

- Represented a plausible, meaningful future "world" (e.g., uncertainties related to cost, regulation and environment)
- Were unique among the scenarios being considered for study
- Reflected a future that TVA could find itself in during the timeframe studied in this IRP

- Placed sufficient stress on the resource selection process
- Provided a foundation for analyzing the robustness, flexibility and adaptability of each combination of various supply- and demand-side options
- Captured relevant key stakeholder interests

A summary of the scenarios selected for the IRP analysis is shown in Figure 6-2. During the scoping phase in summer 2009, Scenarios 1 through 6 were developed for use in the Draft IRP analysis. Scenario 7 was also developed as a reference case in the Draft IRP. It closely resembled TVA's long-term planning outlook at the time the original scenarios were developed. Another reference case, Scenario 8 was added after the publication of the Draft IRP. It captured the impacts of the recent recession and was used in subsequent analysis.

Scenario	Key Characteristics
1 Economy Recovers Dramatically	• Economy recovers stronger than expected and creates high demand for electricity • Carbon legislation and renewable electricity standards are passed • Demand for commodity and construction resources increases • Electricity prices are moderated by increased gas supply
2 Environmental Focus is a National Priority	• Mitigation of climate change effects and development of a "green economy" is a priority • The cost of CO_2 allowances, gas and electricity increase significantly • Industry focus turns to nuclear, renewables, conservation and gas to meet demand
3 Prolonged Economic Malaise	• Prolonged, stagnant economy results in low to negative load growth and delayed expansion of new generation • Federal climate change legislation is delayed due to concerns of adding further pressure to the economy
4 Game-changing Technology	• Strong economy with high demand for electricity and commodities • High price levels and concerns about the environment incentivize conservation • Game-changing technology results in an abrupt decrease in load served after strong growth
5 Energy Independence	• The U.S. focuses on reducing its dependence on non-North American fuel sources • Supply of natural gas is constrained and prices for gas and electricity rise • Energy efficiency and renewable energy move to the forefront as an objective of achieving energy independence
6 Carbon Regulation Creates Economic Downturn	• Federal climate change legislation is passed and implemented quickly • High prices for gas and CO_2 allowances increase electricity prices significantly • U.S. based energy-intensive industry is non-competitive in global markets and leads to an economic downturn
7 Reference Case: Spring 2010	• Economic growth lower than historical averages • Carbon legislation is passed and implemented by 2013 • Natural gas and electricity prices are moderate
8 Reference Case: Great Recession Impacts Recovery	• Economic outlook includes economic recovery, but growth is at a slightly lower rate than Scenario 7 due to lingering recession impacts • Natural gas prices are lower to reflect recent market trends

Figure 6-2 – Scenarios Key Characteristics

Determination of Scenario Uncertainty Values

Once each of the key uncertainties were defined, specific numerical values for each aspect of the scenarios were developed utilizing the following assumptions:

- Climate change uncertainty will be based upon stringency of requirements and timeline required for compliance and cost of CO_2 allowances
- An aggressive EPA regulatory schedule is expected to create additional compliance requirements (e.g., Hazardous Air Pollutants Maximum Achievable Control Technology [HAPs MACT], revised ambient air standards, etc.)
- Command and control regulations for HAPs MACT will likely drive plant-by-plant compliance
- RES will help accomplish GHG reduction required at the federal level
- The spot price of electricity will be correlated with the price of natural gas and coal
- Demand, primarily driven by economic conditions, will be affected by energy efficiency, demand response and other factors
- Schedule risk will be related to demand as well as the uncertainty of permitting and licensing generation and transmission projects
- Economic conditions and associated inflationary pressures will become the primary drivers for changes in financing costs
- Construction costs will be driven by demand as well as availability of labor, equipment, design and raw materials
- Economic conditions will become the primary driver, but the legislative/regulatory environment will apply additional pressure by introducing uncertainty related to potential schedule impacts
- Cost and availability of contract power purchases will be primarily driven by economic conditions and local area demand (i.e., load growth)

A detailed description of each scenario's uncertainty values is shown in Figure 6-3.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 Game-changing Technology	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010	Scenario 8 Reference Case: Great Recession Impacts Recovery
GHG requirements	CO_2 price \$27/ ton (\$30/metric ton) in 2014 and \$82 (\$90/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price \$17/ ton (\$19/metric ton) in 2012 and \$94 (\$104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	No federal requirement (CO_2 price = \$0/ton)	CO_2 price \$18/ ton (\$20/metric ton) in 2013 and \$45 (\$50/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price \$18/ ton (\$20/metric ton) in 2013 and \$45 (\$50/metric ton) by 2030. 77% allowance allocation 41% by 2030	CO_2 price \$17/ ton (\$19/metric ton) in 2012 and \$94 (\$104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	CO_2 price \$15/ ton (\$17/metric ton) in 2013 and \$56 (\$62/metric ton) by 2030. 77% allowance allocation, 39% by 2030	Same as Scenario 7
Environmental outlook	Same as Scenario 7	SO_2 controls 2017 NO_x controls Dec 2016 Hg MACT 2014 HAP MACT 2015	No additional requirements (CAIR requirements, with no MACT requirements)	Same as Scenario 7	Same as Scenario 7	Same as Scenario 7	SCR all units by 2017 FGD all units by 2018 HAPs MACT by 2015	Same as Scenario 7
Energy efficiency and RES	RES – 3% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	No federal requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 3% by 2012, 15% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	Same as Scenario 7
Total load	Med grow to High by 2015; High Dist: Alcoa Returns in 2010+; USEC stays forever, Dept Dist same as Scenario 7	Medium case, then 2012 40% rate increase; Low Dist: DS customer reductions (steel/ paper plants); USEC stays forever; Dept Dist same as Scenario 7	Low load case; Low Dist: Alcoa not returning, No HSC & Wacker, USEC leaves June 2013; Dept Disc same as Scenario 7	Med-High load growth through 2020, then 20% decrease 2021-2022 including USEC departure, reduced dist sales & extended TOU	Medium case, then 20% rate increase in 2014; unrestricted PHEV included, TOU	Medium load case 2010-2011; 2012 low case then flat w/no growth; USEC leaves 2013; Alcoa not returning, HSC & Wacker not in, TOU	Moderate growth	Moderate to low growth
Capital expansion viability & costs	Moderate schedule risk	High schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk
Financing	Higher than Scenario 7 – higher inflation due to higher economic growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Same as Scenario 7 – increased productivity due to technology leads to stronger economic wealth and non-inflationary money growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Based on current borrowing rate	Based on current borrowing rate
Commodity prices	Gas & coal higher than Scenario 7	Gas higher; coal lower than Scenario 7	Gas much lower & coal much higher than Scenario 7	Gas lower & coal slightly higher than Scenario 7	Gas & coal higher than Scenario 7	Gas & coal much lower than Scenario 7	Gas - \$6-8 mmBTU Coal - \$40/ton	Gas - \$5-7/mmBTU Coal - \$40/ton
Contract purchase power cost	Much higher cost & lower availability	Higher cost & lower availability	Same as Scenario 7, then much lower cost with high availability	Higher cost & lower availability, then much lower cost with high availability after load decrease	Higher cost & lower availability	Lower cost with high availability	Moderate cost & availability	Moderate cost & availability
Construction cost escalation	Much higher than Scenario 7 – high economic growth causes high demand for new plants and high escalation rate	Somewhat higher than Scenario 7 – due to "construction costs escalating at high rate due to large volume of nuclear, renewables and env controls projects". High regulatory scrutiny adds to project costs	Lower than Scenario 7 – low load growth leads to low escalation	This scenario has two stages of escalation: 1) higher than Scenario 7 due to high load growth early, then 2) lower escalation when game-changing technology hits	Somewhat higher than Scenario 7 – moderately strong economy and load growth leads to somewhat higher than base escalation	Lower than Scenario 7 – negative load growth, very weak economy and high renewables lead to low escalation	Moderate escalation	Moderate escalation

Figure 6-3 – Scenario Descriptions

6.1.2 Development of Planning Strategies

After development of the scenarios, planning strategies were designed to test the various business decisions and portfolio choices that TVA has control over and might consider. Strategies are very different from the scenarios. Whereas, scenarios describe plausible futures and include factors that TVA cannot control, strategies describe business decisions over which TVA has full control. In the end, a well-designed strategy would perform well in many possible scenarios whereas a poorly designed strategy would frequently not perform well.

The following three-step process was used to design the strategies in this IRP:

1. Identification of key components
2. Development of strategies using key components
3. Definition of strategy

Planning strategies represent decisions and choices over which TVA has full control.

Identification of Key Components

To define the planning strategies, nine distinct categories of components were identified. The choice of components was influenced by comments received during the public scoping period and input from the SRG. Comments stated that TVA should challenge its targets for EEDR and renewables beyond the current portfolios. Accordingly, the ranges for both components were significantly expanded. The components for the planning strategies are described in Figure 6-4.

Component	Description	Type
EEDR portfolio	The level of EEDR included in each strategy	Defined Model Input
Renewable additions	The amount of renewable resources added in each strategy	Defined Model Input
Coal-fired capacity idling	A proposed schedule of coal-fired unit idling that will be tested in each strategy	Defined Model Input
Energy storage	Option to include a pumped-storage unit in selected strategies	Defined Model Input
Nuclear	Constraints related to the addition of new nuclear capacity	Constraint
Coal	Limitations on technology and timing for new coal-fired plants	Constraint
Gas-fired supply (self-build)	Limitations on gas-fired unit expansion	Constraint
Market purchases	Level of market reliance allowed in each strategy	Constraint
Transmission	Type and level of transmission infrastructure required to support resource options in each strategy	Constraint

Figure 6-4 – Components of Planning Strategies

As noted in Figure 6-4, there were two types of components, used in the model.

Defined model inputs	These components were scheduled or predetermined. This applied to both the timing and the quantity of specific asset decisions
Constraints in the model optimization	These components constrained the optimization of asset choices such as minimum build times, technology limitations and other strategic constraints including limits on market purchases. The capacity optimization model selected resources that were consistent with these constraints

Development of Strategies Using Key Components

TVA combined these nine components and created five distinct planning strategies for the Draft IRP analysis. Figure 6-5 lists the five distinct planning strategies and their key characteristics.

Planning Strategy	Key Characteristics
A Limited Change in Current Resource Portfolio	• Retain and maintain existing generating fleet (no additions beyond Watts Bar Unit 2) • Rely on the market to meet future resource needs
B Baseline Plan Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Assumes idling of approximately 2,000 MW of coal-fired capacity • Includes EEDR portfolios and wind PPAs
C Diversity Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Increases the contribution from EEDR portfolio and new renewables • Adds a pumped-storage unit • Assumes idling of approximately 3,000 MW of coal-fired capacity
D Nuclear Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Includes an increased EEDR portfolio compared to other strategies • Assumes idling of approximately 7,000 MW of coal-fired capacity • Includes new renewables (same as Strategy C) • Includes a pumped-storage unit
E EEDR and Renewables Focused Resource Portfolio	• Assumes greatest reliance on EEDR portfolio of any strategy and includes largest new renewable portfolio • Assumes idling of approximately 5,000 MW of coal-fired capacity • Delays nuclear expansion until 2022

Figure 6-5 – Planning Strategies Key Characteristics

Definition of Strategy

Once each strategy's key characteristics were defined, specific numerical values for each component of each strategy were defined as shown in Figure 6-6.

Components	Strategy A Limited Change in Current Resource Portfolio	Strategy B Baseline Plan Resource Portfolio	Strategy C Diversity Focused Resource Portfolio	Strategy D Nuclear Focused Resource Portfolio	Strategy E EEDR and Renewable Focused Resource Portfolio
EEDR	1,940 MW & 4,725 annual GWh reductions by 2020	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	4,000 MW & 8,900 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020
Renewable additions	1,300 MW & 4,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy A	2,500 MW & 8,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy C	3,500 MW & 12,000 GWh competitive renewable resources or PPAs by 2020
Idled coal-fired capacity	No fossil fleet reductions	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	7,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017
Energy storage	No new additions	Same as Strategy A	Add on pumped-storage unit	Same as Strategy C	Same as Strategy A
Nuclear	No new additions after WBN2	First unit online no earlier than 2018 Units at least 2 years apart	Same as Strategy B	First unit online no earlier than 2018 Units at least 2 years apart	First unit online no earlier than 2022 Units at least 2 years apart Additions limited to 3 units
Coal	No new additions	New coal units are outfitted with CCS First unit online no earlier than 2025	Same as Strategy B	Same as Strategy B	No new additions
Gas-fired supply (self-build)	No new additions	Meet remaining supply needs with gas-fired units	Same as Strategy B	Same as Strategy B	Same as Strategy B
Market purchases	No limit on market purchases beyond current contracts and extensions	Purchases beyond current contracts and contract extensions limited to 900 MW	Same as Strategy B	Same as Strategy B	Same as Strategy B
Transmission	Potentially higher level of transmission investment to support market purchases Transmission expansion (if needed) may have impact on resource timing and availability	Complete upgrades to support new supply resources	Increase transmission investment to support new supply resources and ensure system reliability Pursue inter-regional projects to transmit renewable energy	Same as Strategy C	Potentially higher level of transmission investment to support renewable purchases Transmission expansion (if needed) may have impact on resource timing and availability

Defined model inputs ☐ Optimized model inputs

Figure 6-6 – Strategy Descriptions

Strategy components were utilized in the modeling in several different ways. For example, Strategy A has specific defined constraints, such as including no new coal additions and 1,300 MW of renewable resource additions. Other components specified timing, such as adding nuclear resources no earlier than 2018 and no new coal additions in Strategy B. Reactive constraints were also identified, such as the need to build additional transmission capacity if imports from renewables exceed a certain limit.

6.2 Resource Portfolios Optimization Modeling

The generation of resource portfolios was a two-step process. First, an optimized capacity expansion plan was generated, which was then followed by a financial analysis. This process was repeated for each strategy/ scenario combination and for additional sensitivity runs.

6.2.1 Development of Optimized Capacity Expansion Plan

TVA utilized a capacity optimization model, System Optimizer, which is an industry standard software model developed by Ventyx. This model utilized an optimization technique where an "objective function" (i.e., total resource plan cost) was minimized and subject to a number of constraints by using mixed integer linear programming.

Resources were selected by adding or subtracting assets based on minimizing the present value of revenue requirements (PVRR). PVRR represents the cumulative present value of total revenue requirements for the study period based on an eight percent discount rate. In other words, it is the today's value of all future costs for the study period discounted to reflect the time value of money and other factors, such as investment risk.

In addition, the following constraints were observed:

- Balance of supply and demand
- Energy balance
- Reserve margin
- Generation and transmission operating limits
- Fuel purchase and utilization limits
- Environmental stewardship

System Optimizer uses a simplified dispatch algorithm to compute production costs. The model used a "representative hours" approach in which average generation and load values in each representative period within a week were scaled up appropriately to span all hours of the week and days of the months.

Year-to-year changes in the resource mix were then evaluated and infeasible states were eliminated. The least-cost path (based on lowest PVRR) from all possible states in the study period was retained in the Draft IRP as the optimized capacity expansion plan.

6.2.2 Evaluation of Detailed Financial Analysis

Next, each capacity expansion plan was evaluated using an hourly production costing algorithm, which calculated detailed production costs of each plan, including fuel and other variable operating costs. These detailed cost simulations provided total strategy costs and financial metrics that were used for evaluation of the results.

This analysis was accomplished using another Ventyx product called Strategic Planning (MIDAS). This software tool uses a chronological production costing algorithm with financial planning data used to assess plan cost, system rate impacts and financial risk. It also utilized a variant of Monte Carlo analysis[1], which is a sophisticated analytical technique that varies important drivers in multiple runs, to create a distribution of total costs rather than a single point estimate, which allows for risk analysis. The Monte Carlo analysis in MIDAS utilized 13 key variables.

The following variables were selected by TVA for the analysis:

- Commodity prices – natural gas, coal, CO_2, SO_2 and NO_x allowances
- Financial parameters – interest rates and electricity market prices
- Operating costs – capital as well as operation and maintenance
- Dispatch costs – hydro generation, fossil and nuclear availability
- Load forecast uncertainty

Total PVRR for each resource plan was calculated taking into account additional considerations. These considerations included the cash flows associated with financing. The model generated multiple combinations of the key assumptions for each year of the study period and computed the costs of each combination. Capital costs for supply-side options were amortized for investment recovery using a real economic carrying cost method that accounted for unequal useful lives of generating assets.

[1]Monte Carlo analysis is also referred to as stochastic analysis

Present value calculations are widely used in business and economics to provide a means to compare cash flows at different times on a meaningful basis. It also ensures that assets with higher capital costs and longer service lives are not unduly penalized relative to assets with lower capital costs and relatively shorter economic lives.

The short-term rate metric was also calculated and provided an alternative representation of the revenue requirements for the 2011-2018 timeframe expressed per MWh. This metric was developed to focus on the near-term impacts to system cost in recognition of TVA's current debt cap of $30 billion and the likelihood that the majority of capital expenditures in the short–term[1] may have to be funded primarily from rates.

6.2.3 Development of Portfolio

Portfolios are the output of the modeling process described in Section 6.2 – Resource Portfolios Optimization Modeling, and represent the outcome of choices made for a given view of the future. During the Draft IRP process, an optimized portfolio was developed for each of the five planning strategies within each of the six scenarios and for the Reference Case: Spring 2010. The end result was 35 distinct portfolios. Each portfolio represented a 20-year capacity expansion plan. The portfolios consisted of assets that represented various resource selections and cost characteristics optimized to meet TVA's capacity and energy needs for the IRP study period.

Due to the nature of the analysis, certain elements (i.e., emphasis on EEDR and nuclear energy) of some strategies remained relatively constant across the scenarios. However, other elements (i.e., amount of natural gas-fired capacity and market purchases) were variable and determined by the interplay between each planning strategy and the scenario within which it was analyzed.

6.3 Development of Evaluation Scorecard

The use of a scenario planning approach, combined with multiple strategies to be considered, resulted in a large number of distinct 20-year resource portfolios that required analysis and evaluation. Rather than looking for the best single solution contained within a large number of portfolios, the scenario planning approach looked for trends or characteristics common to multiple portfolios with a focus on outcomes considered to be successful and the strategies that guided those outcomes. Definition of what is considered successful, although difficult, was a key component in the evaluation of the planning strategies. Development of a scorecard to communicate the success or failure of the different portfolios was vital to the success of this evaluation process.

[1]prior to 2018

The following sections describe the creation of the IRP scorecard, including development of the ranking and strategic metrics. Although not part of the scorecard, the development of a technology innovation narrative is also discussed below.

6.3.1 Scorecard Design

Identification of preferred planning strategies in the Draft IRP and development of the Recommended Planning Direction in the final IRP involved a trade-off analysis. The analysis was focused on multiple metrics of cost, risk, environmental impacts and other aspects of TVA's overall mission.

A scorecard was designed for each strategy and was used to facilitate this trade-off analysis. The scorecard template (Figure 6-7) was comprised of two sections – ranking metrics and strategic metrics. A technology innovation narrative was included apart from the scorecard to help identify which strategies would be supported by particular technology innovations.

	Ranking Metrics			Strategic Metrics				
	Financial Impact			Environmental Stewardship			Economic Impact	
Portfolio	Cost	Risk	Ranking Metric Score	Carbon Footprint	Water Impact	Waste Impact	Total Employment	Growth in Personal Income
		Total Score:						

Figure 6-7 – Planning Strategy Scorecard

Ranking Metrics

Ranking metrics were used to quantify the financial impact of each given portfolio. Two metrics, cost and risk, were selected based on their ability to highlight differences between the portfolios. To further highlight differences, the ranking metric score was calculated as a blend of the two metric's scores.

Cost Metric

Production of the financial metrics PVRR and short-term rates was described in Section 6.2.1. The cost metric used in the strategy scorecard combined these two metrics using the following weighted formula:

Cost = 0.65 * PVRR + 0.35 * short-term rates

By considering the expected values for PVRR and short-term rates, TVA was able to better evaluate the cost and rate implications for various portfolios. The inclusion of both short-term rates and total revenue requirements helped to facilitate a trade-off analysis of alternative resource plans. This allowed TVA to explicitly evaluate funding implications, consistent with stakeholder concerns regarding increasing rate pressures.

Risk Metric

The PVRR risk metric was computed using both a risk ratio and a risk/benefit ratio metric for each portfolio, as shown in Figure 6-8.

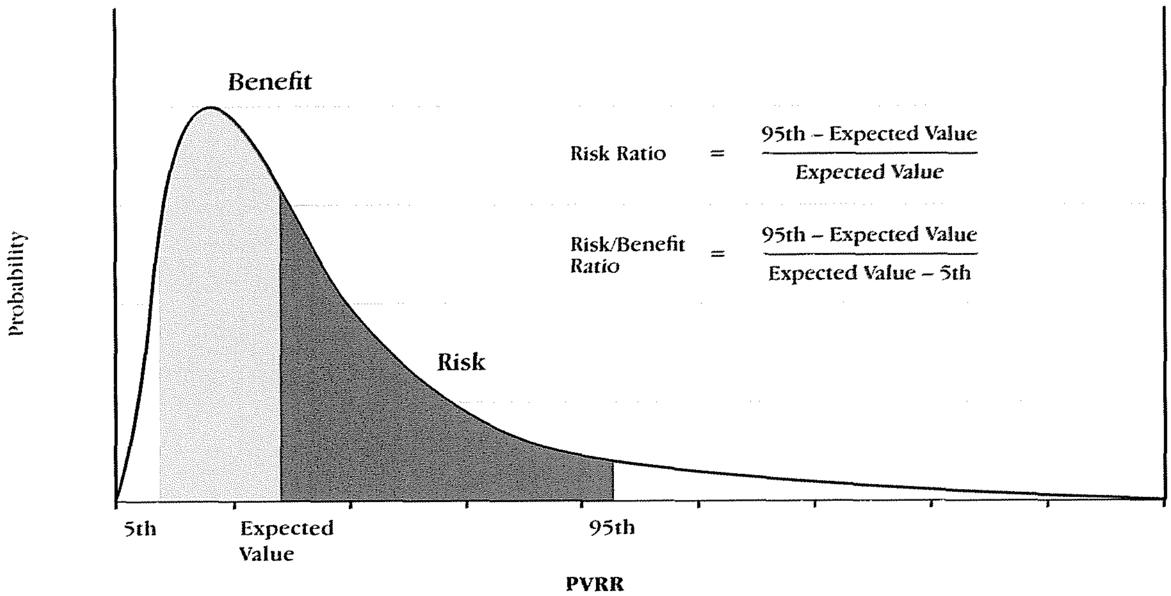


Figure 6-8 – Financial Risk Metrics

The risk metric used in the strategy scorecard combined these two metrics using the following weighted formula.

Risk = 0.65 * risk ratio + 0.35 * risk/benefit ratio

The risk ratio was expressed as the ratio of the difference between the 95th percentile of PVRR from the stochastic analysis and the expected value. It is a measure of the absolute "size" of the risk relative to the expected cost under each strategy within each scenario. A higher value signifies a portfolio with a relatively higher level of risk. The risk/benefit ratio captured the "risk" of a portfolio by examining the potential of exceeding the expected PVRR compared to the benefit of not exceeding the expected PVRR, expressed as a ratio. It compared the potential risks and the potential benefits of a strategy to determine whether or not the "risks and rewards" balance was weighted in favor of the customer.

Ranking Metric Score

The ranking metrics score combined the cost and risk metrics using the following weighted formula.

Ranking metrics score = 0.65 * cost + 0.35 * risk

This metric allowed evaluation of the interaction between financial risks and overall plan cost. For example, desirable low costs may require accepting a greater risk exposure, or to achieve an acceptable level of financial risk may mean selecting a plan with costs that are slightly higher than the least-cost option. The trade-offs required to balance these competing objectives helped identify the preferred planning strategies in the Draft IRP and the Recommended Planning Direction in the final IRP.

Strategic Metrics

Strategic metrics developed to consider other parts of TVA's mission were paired with ranking metrics to complete the IRP scorecard. Two strategic metrics were developed – environmental stewardship and economic impact.

Environmental Stewardship Metric

The environmental stewardship metric was developed to evaluate air, water and waste impacts. In the air metric evaluation, CO_2, SO_2, NO_x and Hg emissions were calculated for each portfolio. Emissions trends for SO_2, NO_x and Hg were steeply reduced because all cases chose large levels of coal-fired unit idling (2,000-7,000 MW) and controlled (90 percent or better emission removal rates) operating units in the future. For simplicity, the air metric was represented as a CO_2 impact footprint factor (annual average tons) because similar trend lines were tracked in all cases for CO_2. No additional significant insight was gained using all air emissions as opposed to using only CO_2. Therefore, the air metric is represented as a CO_2 impact "footprint" factor (annual average tons).

The water component of the environmental stewardship metric represents the thermal load produced through the condenser cooling cycle from steam generating plants to measure thermal impacts to the environment. The water impact was estimated based on the total heat dissipated by the condenser in the generation cooling cycle.

In addition to air and water impacts, certain generation sources produce waste streams that require disposal. The waste component used in this analysis focused on coal and nuclear generation, which are the primary sources of waste streams. The volumetric and disposal costs were used to better normalize differences in mass generated (tons). Waste streams that were estimated included coal ash, flue gas desulfurization/scrubber waste and high- and low-level nuclear waste.

The final evaluation criteria for both water and waste relied on surrogate measures as a proxy for environmental impacts. Both provided a reasonable and balanced method for evaluating planning strategies when compared with other components. Additional detail on the environmental stewardship metrics is in Appendix A – Method for Computing Environmental Impact Metrics.

Economic Impact Metric

Economic impact metrics were included to provide an indication of the impact of each strategy on the general economic conditions in the Tennessee Valley region. The economic metrics were represented by total employment and personal income. These metrics were compared to the impacts of Strategy B – Baseline Plan Resource Portfolio, in Scenario 7.

The IRP study defined economic impact as growth in regional economic activity. Measurement criteria included total personal income in "constant" dollars (i.e., with inflation accounted for) and total employment. These provided measures for the effects of the various planning strategies on the overall, long-term health and welfare of the economy over the next 20 years. This analysis concentrated on changes to the welfare of the general economy due to the strategies. It did not address changes to the distribution of income or employment.

In general, the greater the direct regional expenditures associated with a particular portfolio, the more positive were the effects on the regional economy. This can be offset by the fact that higher rates caused by higher costs have a negative effect on the regional economy. Thus, a resource portfolio that has high expenditures in the Tennessee Valley region may also have high costs and high rates.

The economic impact metrics for a particular planning strategy could be positive or negative depending on the net sum of the expenditure effects and the cost effects. More details about the methodology used to determine the economic impact metrics for the planning strategies is in Appendix B – Method for Computing Economic Metrics.

Scorecard Calculation and Color Coding

The ranking metrics in the scorecard for this IRP were expressed in terms of a 100-point score while ensuring that the relative relationship between the actual values for each portfolio in the strategy was maintained. The following process was used to compute the scores:

- Actual values of ranking metrics (i.e., PVRR, short-term rate impacts) were converted to a relative score on a 100-point scale. This type of scoring helped to assess and prioritize risk and identify the best possible solution
- The highest ranked ("best") value received a 100
- The rest of the scores were based on their relative position to the "best" value (e.g., a value that is 75 percent of the "best" would receive a 75)
- A color-coding method was used to assist in visual comparison of portfolio results. The coding was done within a given scenario. The "best" value for each metric was coded green, the "worst" value was coded red and the values in between were shown with a shaded color that corresponded to the relationship of the score values

An example of the translation from actual values to ranking metric scores is shown in Figure 6-9. The figure shows the conversion for the short-term rate metric.

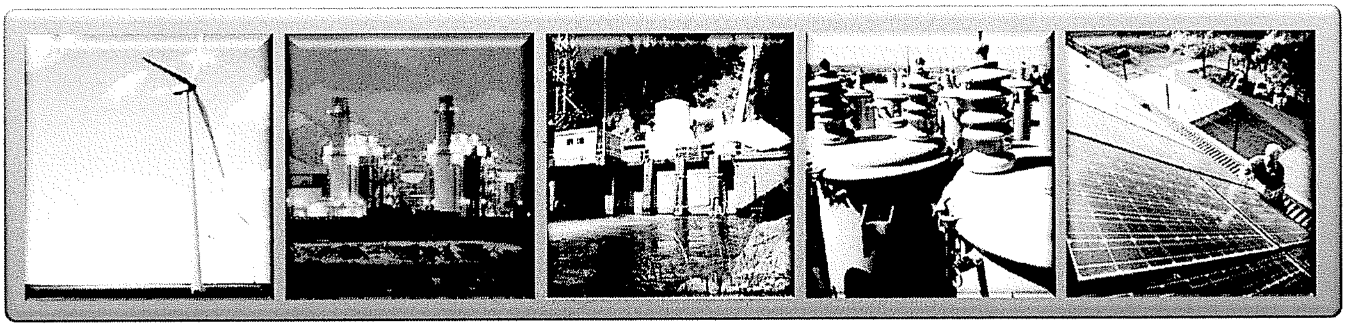
EXHIBIT

PACIFICORP

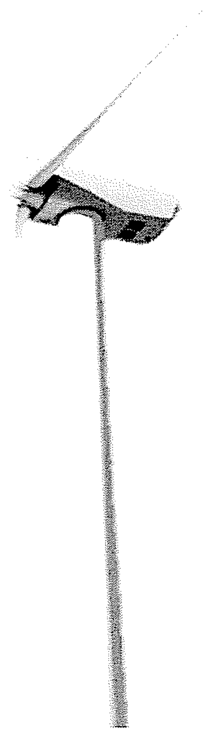
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

2011 Integrated Resource Plan

Volume I



Let's turn the answers on.



March 31, 2011

SC\NRDC EXHIBIT 6

This 2011 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
http://www.pacificorp.com

This report is printed on recycled paper

Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
Wind Turbine: *Dunlap I Wind Project*

TABLE OF CONTENTS

INDEX OF TABLES

Carbon Dioxide Regulatory Compliance Scenarios

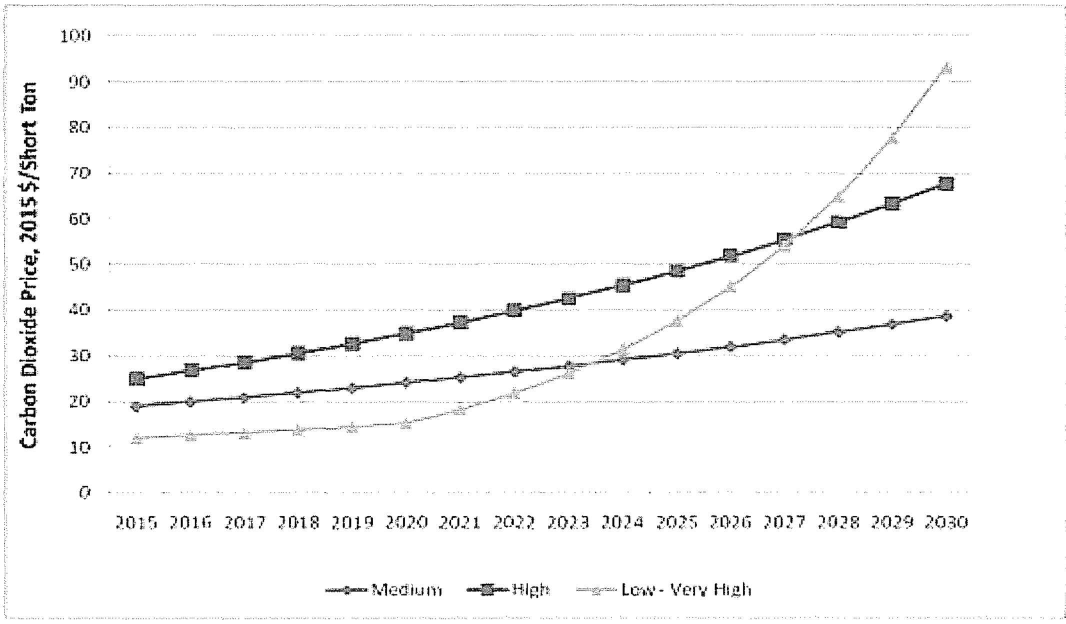
Carbon Dioxide Tax Scenarios

Table 7.2 shows the four CO_2 tax scenarios developed for the IRP. The Medium and High scenarios reflect CO_2 price trajectories contained in recent federal greenhouse gas emission policy proposals, and assume a 2015 start date. The Medium scenario assumes a starting cost of $19 per short ton (2015 dollars) beginning in 2015, with 3 percent annual real escalation plus annual inflation. The High scenario assumes a starting cost of $25 per short ton (2015 dollars) beginning in 2015, with 5 percent annual real escalation plus annual inflation. The Low to Very High scenario assumes a starting cost of $12 per short ton (2015 dollars) beginning in 2015, with 3 percent annual real escalation plus annual inflation through 2020; beginning in 2021, the cost escalates at an 18% annual escalation rate plus inflation. Figure 7.3 is a comparison of the three CO_2 tax trajectories.

Table 7.2 – CO_2 Tax Scenarios

	CO_2 Price, 2015$/short ton			
Year	**None**	**Medium**	**High**	**Low to Very High**
2015	0.00	19.00	25.00	12.00
2016	0.00	19.93	26.73	12.59
2017	0.00	20.93	28.60	13.22
2018	0.00	21.97	30.60	13.88
2019	0.00	23.05	32.71	14.56
2020	0.00	24.18	34.97	15.27
2021	0.00	25.34	37.34	18.30
2022	0.00	26.53	39.85	21.90
2023	0.00	27.81	42.55	26.24
2024	0.00	29.14	45.45	31.43
2025	0.00	30.54	48.54	37.65
2026	0.00	32.00	51.84	45.11
2027	0.00	33.57	55.42	54.09
2028	0.00	35.22	59.24	64.85
2029	0.00	36.94	63.33	77.75
2030	0.00	38.75	67.70	93.23

Figure 7.3 – Carbon Dioxide Price Scenario Comparison



Emission Hard Cap Scenarios

PacifiCorp also modeled two CO_2 system emission hard caps scenarios as alternate compliance mechanisms.[53] Two emission cap scenarios were developed:

- Base: 15 percent below 2005 levels by 2020, and 80% by 2050
- Oregon: 10 percent below 1990 levels by 2020—the Oregon target in H.B. 3543—and 80 percent below by 2050

The hard caps go into effect in 2015. Table 7.3 shows the hard cap emission limits for each scenario.

Table 7.3 – Hard Cap Emission Limits (Short Tons)

Year	Base Emission Limits (15% below 2005 Levels by 2020; 80% by 2050)	Oregon H.B. 3543 Emission Limits (10% below 1990 Levels by 2020; 80% by 2050)
1990		49,878
2005	60,938	
2015	56,968	51,075
2016	55,934	49,838
2017	54,900	48,601
2018	53,866	47,364
2019	52,832	46,127

53 The Public Utility Commission of Oregon's 2008 IRP acknowledgment order (Order No. 10-066 under Docket No. LC 47) included a requirement to provide analysis of potential hard cap regulations.

Year	Base Emission Limits (15% below 2005 Levels by 2020; 80% by 2050)	Oregon H.B. 3543 Emission Limits (10% below 1990 Levels by 2020; 80% by 2050)
2020	51,798	44,890
2021	50,477	43,726
2022	49,157	42,562
2023	47,837	41,398
2024	46,516	40,235
2025	45,196	39,071
2026	43,876	37,907
2027	42,555	36,743
2028	41,235	35,579
2029	39,915	34,416
2030	38,594	33,252
2050	12,188	9,976

For representing CO_2 emissions associated with firm market purchases and system balancing spot market transactions, PacifiCorp's reporting protocols for calculating its greenhouse gas inventory requires using the EPA's e-Grid sub-region output emission factors for unspecified market transactions. Consequently, the CO_2 emission rate of 902 lbs/MWh is applied for the Mid-Columbia, COB, Mona, and Mead markets, and 1,300 lbs/MWh is applied for the Palo Verde and Four Corners markets.

When modeling a hard cap in System Optimizer, the model generates shadow emission prices in order to meet the hard cap. For example, if the hard cap is not met then the shadow price is increased to decrease the output of the emission-producing stations. These shadow prices are imported into the PaR model to simulate emission-constrained dispatch. Table 7.4 shows the shadow prices generated for the four hard cap cases. The medium CO_2 tax is also used for hard cap cases to reflect assumed regional or federal emission prices that impact wholesale electricity and gas commodity prices used for portfolio modeling. Note that for PaR portfolio cost reporting, PacifiCorp applied the CO_2 tax values to emission quantities rather than the System Optimizer shadow costs to maintain cost comparability among the portfolios.

Table 7.4 – CO_2 Emission Shadow Costs Generated by System Optimizer for Emission Hard Cap Scenarios

Case	15	16	17	18
Hard Cap	Base	Base	Base	Oregon H.B. 3543
Gas Price	Low	Medium	High	Medium
Year	Shadow CO_2 Emission Price ($/ton)			
2015	0	0	0	37
2016	10	8	1	39
2017	11	24	16	35
2018	14	30	34	37
2019	15	34	39	40
2020	17	36	50	43
2021	21	40	64	47
2022	24	43	71	55
2023	28	50	78	70

Case	15	16	17	18
Hard Cap	Base	Base	Base	Oregon H.B. 3543
Gas Price	Low	Medium	High	Medium
Year	Shadow CO_2 Emission Price ($/ton)			
2024	34	57	85	75
2025	38	60	91	75
2026	47	64	94	77
2027	47	62	95	73
2028	51	71	108	83
2029	63	75	114	101
2030	47	61	78	78

Oregon Environmental Cost Guideline Compliance

The Public Utility Commission of Oregon, in their IRP guidelines, directs utilities to construct a base-case scenario that reflects what it considers to be the most likely regulatory compliance future for CO_2, as well as alternative scenarios "ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities." Modeling portfolios with no CO_2 cost represents the current regulatory level. The Medium scenario was considered the most likely regulatory compliance scenario at the time that IRP CO_2 scenarios were being prepared and vetted by public stakeholders (early fall of 2010). Given the late-2010 collapse of comprehensive federal energy legislation and loss of momentum for implementing federal carbon pricing schemes, there is no "likely" regulatory compliance future at the present time (notwithstanding the U.S. EPA's GHG initiative to revise New Source Performance Standards for electric generating units.) PacifiCorp believes that its CO_2 tax and hard cap scenarios reflect a reasonable range of compliance futures for meeting the Public Utility Commission of Oregon scenario development guideline given continued uncertainty. In particular, it should be noted that the hard cap shadow prices for Case 15 exhibit a more moderate trajectory than the Medium scenario, effectively providing a "low" CO_2 tax case for portfolio evaluation.

Case Definition

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations in inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values to ensure that a reasonably wide range in potential outcomes is captured. For the 2011 IRP, PacifiCorp developed a total of 49 cases.

PacifiCorp defined three types of cases: Energy Gateway scenario evaluation cases, core cases, and sensitivity cases. Energy Gateway scenario evaluation cases were designed to help PacifiCorp's transmission planning department evaluate four Energy Gateway expansion options based on System Optimizer portfolio modeling results. These 16 cases supplement other Energy Gateway economic analysis conducted with the IRP models, profiled in Appendix C.

Core cases focus on broad comparability of portfolio performance results for four key variables. These variables include (1) the level of a per-ton CO_2 tax, (2) the type of CO_2 regulation—tax or hard emission cap, (3) natural gas and wholesale electricity prices based on PacifiCorp's forward price curves and adjusted as necessary to reflect CO_2 tax impacts, and (4) extension date for the federal renewables production tax credit. The Company developed 19 core cases based on a combination of input variable levels. The core case group includes a 2011 business plan "reference" portfolio. This portfolio consists of fixed wind and gas resources for 2011 through 2020, reflecting the major generation projects in the business plan. Also included are four hard cap cases. Because these cases simulate physical emission constraints as opposed to generator emission costs, they do not have emissions profiles comparable to the other portfolios.

In contrast, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 14 sensitivity cases reflecting evaluation of existing coal plant operation, alternative load forecasts, alternative renewable generation cost and acquisition incentives, and demand-side management resource availability assumptions.

In developing these cases, PacifiCorp kept to a target range in terms of the total number (low 50s) in light of the data processing and model run-time requirements involved. To keep the number of cases within this range, PacifiCorp excluded some core cases with improbable combinations of certain input levels, such as a high CO_2 tax and high load growth. (With a high CO_2 tax, a significant amount of demand reduction is expected to occur in the form of energy efficiency improvements, and utility load control programs.)

PacifiCorp also relied heavily on feedback from public stakeholders. The Company assembled an initial set of cases in July 2010, and introduced them to stakeholders at the August 8, 2010, public input meeting. Subsequent updates based on stakeholder comments and Company refinements were reviewed at public input meetings held October 5 and December 15, 2010. One of the key messages from stakeholders was to ensure that the range of cases generate a diverse set of resource types.[54]

Case Specifications

Table 7.5 profiles the portfolio development cases specifications. Reference numbers in the table headings and certain rows correspond to notes providing descriptions of the case variables and explanatory remarks for specific cases that follow the table.

[54] PacifiCorp's IRP public process IRP Web page includes links to documentation on portfolio case development and how stakeholder comments were addressed.

Table 7.5 – Portfolio Case Definitions

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Energy Gateway Scenario Evaluation Cases										
EG1	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG2	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG3	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG4	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG5	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG6	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG7	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG8	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG9	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG10	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG11	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG12	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG13	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG14	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG15	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG16	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG1-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG2-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG3-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG4-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG5-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG6-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG7-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG8-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG9-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG10-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG11-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG12-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG13-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG14-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG15-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG16-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Core Cases										
1	None	None	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
2	None	None	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario
3	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
4	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
5	CO2 Tax	Low to Very High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
6	CO2 Tax	Low to Very High	Low	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
7	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
8	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
9	CO2 Tax	Low to Very High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
9a	Same assumptions as 9, except using two System Optimizer runs; the first, a 12-year run, determines fixed resources for a subsequent 20-year run 13/									
10	CO2 Tax	Low to Very High	Medium	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
11	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
12	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
13	CO2 Tax	Low to Very High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
14	CO2 Tax	Low to Very High	High	Med. Econ. Growth	Extension to 2020	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
15	Hard Cap - Base	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
16	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
17	Hard Cap - Base	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
18	Hard Cap - OR	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
19	2011 Business Plan resources fixed through 2020; optimized thereafter using Medium scenario assumptions								None	Scenario 3
Coal Plant Utilization Sensitivity Cases										
20	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
21	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
22	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
23	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
24	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario
Load Forecast Sensitivity Cases										
25	CO2 Tax	Medium	Medium	Low Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
26	CO2 Tax	Medium	Medium	High Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
27	CO2 Tax	Medium	Medium	High Peak Demand	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
Renewable Resource Sensitivity Cases										
28	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario
29	CO2 Tax	Medium	Medium	Med. Econ. Growth	Alt. Wind Integ. Cost	Current RPS	High Achievable	Current Incentives	None	Base or Scenario
30	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $1.50/Watt Incentive	None	Base or Scenario
30a	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $2.00/Watt Incentive	None	Base or Scenario
DSM Sensitivity Cases										
31	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Class 3 Included	Current Incentives	None	Base or Scenario
32	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Technical Potential	Current Incentives	None	Base or Scenario
33	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Distribution Energy	Current Incentives	None	Base or Scenario

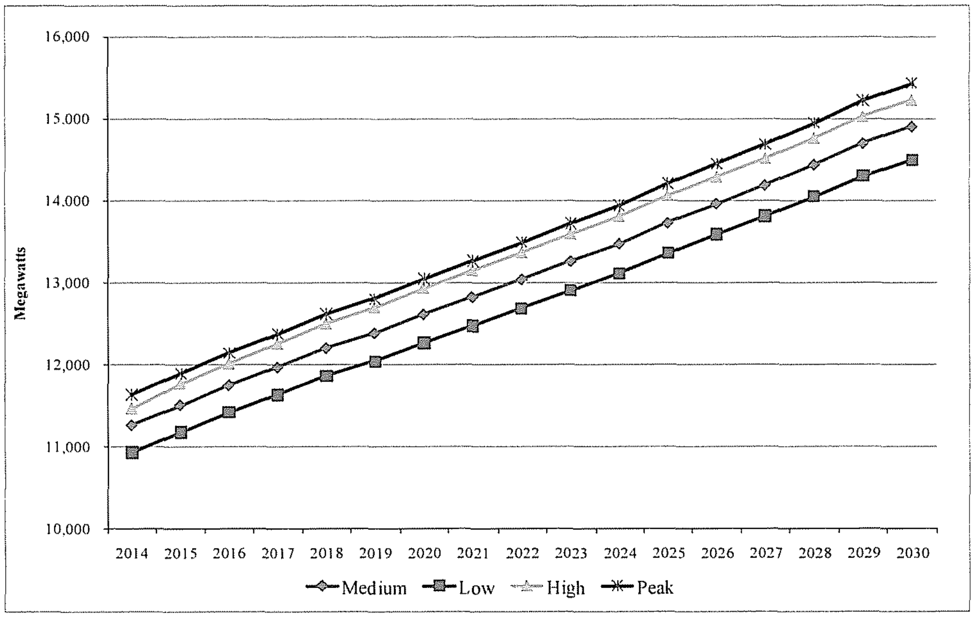
Case Definition Notes

1. The carbon dioxide tax is a variable cost adder for each short ton of CO_2 emitted by PacifiCorp's thermal plants. The CO_2 tax for market purchases is incorporated in the electricity price forecast scenarios as simulated by MIDAS, a regional production simulation model that is described later in this chapter. These marginal wholesale electricity price forecasts, by market hub, are then fed into System Optimizer. The hard cap is a physical CO_2 emissions limit placed on system generation and purchases.

2. The high, medium, and low natural gas price forecasts are based on a review of multiple forecasting service company projections, and incorporate the CO_2 tax assumptions associated with the case definitions. Details on the price forecasts and supporting methodology are provided later in this chapter.

3. The main purpose of the alternative load forecast cases is to determine the resource type and timing impacts resulting from a structural change in the economy. The focus of the load growth scenarios is from 2014 onward. The Company assumes that economic changes begin to significantly impact loads beginning in 2014, the currently planned acquisition date for the next CCCT resource. For the low economic growth scenario (Case 25), another economic recession hits in 2014. For the high economic growth scenario (Case 26), the economy is assumed to fully recover from the current recession by 2014 and significantly expand beginning at that point. Low and high load forecasts are one-percent decreases and increases, respectively, for economic drivers, relative to the Medium forecast. PacifiCorp developed the "high peak demand" forecast by assuming one-in-ten (10 percent probability of exceedence) high temperature loads. Figure 7.4 shows the low, high, and high-peak load forecasts relative to the medium case. Note that the capacities reflect loads before any adjustments for demand-side management programs are applied. See Appendix A for a detailed description of the forecast scenarios.

Figure 7.4 – Load Forecast Scenario Comparison



4. The "PTC extension to 2015" assumption is consistent with PacifiCorp's 2011 business plan. The "PTC extension to 2020" assumption was recommended by a public stakeholder.

   A wind integration cost of $5.38/MWh (versus $9.70/MWh as reported in PacifiCorp's wind integration study dated September 1, 2010) was used for the alternative wind integration cost case as recommended by Renewable Northwest Project based on their independent analysis. The PTC is assumed to expire by 2015 for the alternate wind integration cost case.

5. The current RPS assumption is a system-wide requirement based on meeting existing state RPS targets under the Multi-State Protocol Revised Protocol. States with applicable resource standards include California, Oregon, Washington, and Utah. The table below shows the incremental system renewable energy requirement after accounting for state eligible resources acquired through 2010. Based on RPS compliance analysis using the compliance targets proposed by Senator Jeff Bingaman, along with PacifiCorp's eligible renewable resources through 2010, PacifiCorp would comply with this federal RPS proposal until 2030. The federal RPS scenario assumes the higher Waxman-Markey (H.R. 2454) targets that passed the U.S. House of Representatives in June 2009. This RPS scenario was used for Energy Gateway and 2011 IRP preferred portfolio scenario analysis. Table 7.6 below compares the Bingaman and Waxman-Markey combined renewables/electricity savings compliance targets and the renewable-only targets estimated by PacifiCorp.

Table 7.6 – Comparison of Renewable Portfolio Standard Target Scenarios

		Bingaman		Waxman-Markey (H.R. 2454)	
Year	Current RPS 1/ (System Basis)	Compliance Target	Renewable Percentage 1/	Compliance Target	Renewable Percentage 2/
2015	0.0%	3.0%	2.3%	9.5%	7.1%
2016	0.0%	3.0%	2.3%	13.0%	9.8%
2017	0.0%	3.0%	2.3%	13.0%	9.8%
2018	0.0%	6.0%	4.5%	16.5%	12.4%
2019	0.0%	6.0%	4.5%	16.5%	12.4%
2020	0.1%	6.0%	4.5%	20.0%	15.0%
2021	2.0%	9.0%	6.8%	20.0%	15.0%
2022	2.2%	9.0%	6.8%	20.0%	15.0%
2023	2.2%	12.0%	9.0%	20.0%	15.0%
2024	2.3%	12.0%	9.0%	20.0%	15.0%
2025	3.2%	15.0%	11.3%	20.0%	15.0%
2026	3.2%	15.0%	11.3%	20.0%	15.0%
2027	3.2%	15.0%	11.3%	20.0%	15.0%
2028	3.2%	15.0%	11.3%	20.0%	15.0%
2029	3.1%	15.0%	11.3%	20.0%	15.0%
2030	3.2%	15.0%	11.3%	20.0%	15.0%

1/ Reflects additional renewable energy requirement after accounting for eligible resources acquired through 2010.
2/ Reflects the forecasted renewable portion of a combined renewable/electricity savings requirement.

6. A high achievable percentage assumption of 85 percent for DSM programs applies to all portfolios. The Cadmus Group's base achievable assumption for the 2007 DSM potential study, prior to Company adjustment, was 55 percent.

7. For sensitivity Case 31, System Optimizer is allowed to select price-responsive DSM programs. These programs, outlined in Chapter 6, include residential time-of-use, commercial/industrial real-time pricing, commercial/industrial demand buyback, commercial/industrial load curtailment, commercial critical peak pricing, and *mandatory* irrigation time-of-use rates.

8. This assumption is intended to meet the Public Service Commission of Utah's DSM evaluation requirements. DSM is modeled based on technical potential.

9. PacifiCorp modeled a Washington-only conservation voltage reduction (CVR) resource based on estimated energy savings and costs for 19 distribution feeders analyzed as part of a consultant study.[55] The sensitivity analysis serves as a proof-of-concept test for future resource modeling. The levelized cost and resource capacity by Washington topology bubble is shown in the following table:

Location	Levelized Average Cost 1/ (2010 $/MWh)	Capacity (MW)
Walla Walla	63	0.191
Yakima	66	0.403

1/ Costs exclude credits applied to meet Initiative 937 methodology requirements documented in Chapter 6.

10. This case is intended to meet the Public Service Commission of Utah's distributed solar evaluation requirements. For Case 30, Utah roof-top PV resources were modeled with a program incentive cost (capital cost) of $1,744/kW, which includes a 14 percent administrative and marketing cost gross-up. For Case 30a, the resources were modeled with a program cost of 2,326/kW, including the 14 percent administrative and marketing cost gross-up. Resource potential in Utah is 1.2 MW per year, reaching 24 MW by 2030.[56]

11. The five coal plant utilization sensitivity cases are designed to investigate, as a modeling proof-of-concept, the impacts of CO_2 cost and gas price scenarios on the existing coal fleet after accounting for: incremental environmental compliance, fueling, decommissioning, and coal contract liquidated damages, as well as recovery of remaining plant depreciation. System Optimizer is allowed to select the optimal coal plant shut down dates. This study is limited to CCCT replacement resources with an earliest in-service date of 2016. The simulation period covers 2011 through 2030. More details on specification of the coal plant utilization model set-up are provided later in this chapter.

[55] The study was conducted by a consulting team led by Commonwealth Associates, Inc. The modeled resource reflects preliminary findings of the study. The consulting team applied the Distribution Efficiency Initiative (DEI) average Pacific Northwest conservation load shape to the 19 distribution feeder efficiency measures to derive hourly energy savings for use by System Optimizer. DEI was a three-year study initiated in 2005 by the Northwest Energy Efficiency Alliance to investigate the cost-effectiveness of distribution efficiency and voltage optimization measures.

[56] Resources are modeled by topology bubble. The Utah solar PV resource was located in the Utah North bubble, which includes a portion of Idaho and southwestern Wyoming. The total solar PV capacity potential per year for Utah North is 1.3 MW, consisting of 1.2 MW for Utah, 0.18 MW for Wyoming, and 0.07 MW for Idaho.

12. Energy Gateway transmission scenarios are defined by including certain transmission expansion segments. Table 7.7 shows the segments assigned to the Energy Gateway scenarios. Capital costs for each scenario included in System Optimizer are also shown. PacifiCorp ultimately developed 32 portfolios reflecting the base RPS assumption and the higher Waxman-Markey targets (Cases designated with a "-WM" extension). Modeling assumptions, transmission maps, and results are provided in Chapter 4.

For the Base scenario, both the Populus - Terminal and Mona - Oquirrh projects have a Certificate of Public Convenience and Necessity (CPCN). The Sigurd - Red Butte and Harry Allen projects are not considered transmission resource options because they are reliability/grid reinforcement investments necessary for serving southwestern Utah loads, and not justified based on supply-side resource expansion elsewhere on the system. The "Hemingway - Boardman - Cascade Crossing" transmission project is treated as a resource option in Scenario 3 due to the dependency on the Populus - Hemingway segment.

Table 7.7 – Energy Gateway Transmission Scenarios

Energy Gateway Segments by Scenarios			
Base	**Scenario 1**	**Scenario 2**	**Scenario 3**
Gateway Central (Populus-Terminal and Mona-Oquirrh)	Gateway Central	Gateway Central	Gateway Central
Sigurd - Red Butte	Sigurd - Red Butte	Sigurd - Red Butte	Sigurd - Red Butte
Harry Allen Upgrade	Harry Allen Upgrade	Harry Allen Upgrade	Harry Allen Upgrade
	Windstar - Populus	**Windstar - Populus**	**Windstar - Populus**
		Aeolus - Mona	**Aeolus - Mona**
			Populus - Hemingway
			Hemingway-Boardman-Cascade Crossing
Total Capital Cost (Million $)			
1,776	3,329	4,609	5,888

13. Two portfolios were developed for Case 9. The portfolio for Case 9 is a conventional 20-year System Optimizer run. Portfolio 9a represents the outcome of two System Optimizer runs; the first run was a 12-year run, while the second run was a 20-year run with the resources fixed for the first ten years based on the 12-year run. (The 12-year run mitigates the optimization period end effects that would be present on a ten year run.) These portfolios are intended to support analysis required in the Public Utility Commission of Oregon's 2008 IRP acknowledgment order (Order No. LC 47). They also support the Oregon Commission's "Trigger Point Analysis" IRP standard (Order No. 08-339).

EXHIBIT

2. Planning Scenarios

Highlights

- *Ameren Missouri worked with Charles River Associates to define and model ten planning scenarios.*
- *The planning scenarios are defined by a probability tree which is comprised of three uncertain factors: carbon policy, natural gas prices, and load growth.*
- *The three uncertain factors are dependent in that they have interactive effects. They are also considered to be critical, as different values could sway resource selection.*
- *For each of the three critical dependent uncertain factors, subjective probability distributions were identified by subject matter experts using formal decision analysis techniques.*

Ameren Missouri consulted Charles River Associates (CRA) to help determine the critical factors that should define the planning scenarios, elicit subjective probabilities from Ameren Missouri experts about those variables, and then model those scenarios with their integrated environmental and economic model. Based on prior modeling experience, three interactive variables were chosen to define scenarios and are expected to have the largest impact on future resource choices: carbon policy, natural gas prices, and load growth. Based on the outcomes of the expert interviews, Ameren Missouri adopted 10 scenarios to represent the uncertainty of the three critical variables. CRA modeled each scenario to provide the necessary internally-consistent inputs for further IRP analysis. The load forecasts for Ameren Missouri, as seen in Chapter 3, were developed to be consistent with the same uncertainty expected by internal experts and on which the planning scenarios were based. Chapter 9, Modeling and Risk Analysis, discusses the details of how the scenarios were used to judge the performance of alternative resource plans as well as the results of further sensitivity analysis of additional uncertain factors.

2.1 Scenarios and the Probability Tree

The building and analysis of several "scenarios" of key future market outcomes for national-scale variables is the starting point for the evaluation of resource plans, and the first step of the risk analysis. These scenarios make up a "probability tree," meaning that each scenario has a probability associated with it, and that the scenarios as a group were developed to span a full probable range of relevant market outcomes. The probability tree is developed to describe multiple combinations of critical uncertain factors that have interrelated (or "dependent") impacts on projections of multiple energy and environmental variables. The "critical" variables comprising the probability tree are

SC\NRDC EXHIBIT 7

those for which reasonably likely alternative forecasts could significantly sway the evaluation of candidate resource plans.

For each scenario in the probability tree, Ameren Missouri must have "integrated" sets of forecasts of the "nationally-defined" inputs to IRP calculations of resource plan revenue requirements. In this context, the term "integrated" denotes that all of the individual variable projections for a particular scenario are mutually consistent with one another, which requires a model with the ability to simultaneously simulate interactions in fuel and energy markets, electricity generation system operation, non-electricity sector outcomes, macroeconomic activity levels, and sector-specific responses to emissions limits.

The term "nationally-defined" denotes that the projected outcome is determined by supply and demand events that occur on a scale larger than that of Ameren Missouri or its territory, and would apply to such variables as U.S. electricity demand. Charles River Associates' (CRA's) MRN-NEEM model, a computable general equilibrium representation of the full U.S. economy integrated with a dispatch model of individual electricity generating units, satisfies both of the above criteria. By simulating each scenario as an MRN-NEEM model run, Ameren Missouri can produce integrated, nationally-defined projections of the inputs to the detailed, system-level IRP evaluations.

In the Sensitivity Analysis step of the IRP risk analysis, other uncertain variables are evaluated and the critical independent uncertain factors are identified and then added to the scenario probability tree. As the name implies, independent uncertain factors are those whose impacts on multiple energy and environmental projections are not regarded as interrelated. This topic is discussed in detail in Chapter 9.

2.2 Critical Dependent Uncertain Factors

To determine which variables should comprise the probability tree and to determine the associated probabilities, Ameren Missouri consulted the firm Charles River Associates (CRA) to assist. Although Ameren Missouri developed a list of 22 candidate uncertain factors, as seen in Table 2.1,[1] the relevant variables for this step are those which are subject to a range of uncertainty within which different values might significantly sway the evaluation of

Table 2.1 Candidate Uncertain Factors

Load Growth	DSM Cost
Interest Rates	Off-System Sales
Carbon Policy	Investment Tax Credit
Fuel Prices	Variable O&M
Project Cost	Return on Equity
Project Schedule	Hourly Price Shapes
Purchased Power	Power Price Volatility
Emissions Prices	Nuclear Incentives
Fixed O&M	Wind Capacity Factor
Forced Outage Rate	Solar Capacity Factor
DSM Load Impacts	Transmission Interconnection Costs

[1] 4 CSR 240-22.070(2); 4 CSR 240-22.070(11)(A)2.;

resource plans (i.e., can be critical to the resource plan decision), and that are nationally-defined in scope. Identifying individual variables rather than complex packages of multiple variable outcomes facilitates the expert elicitation process described in the next section of this chapter. The various combinations of these critical, nationally-defined variables, and their associated likelihoods, will form the scenarios represented in the final probability tree. Each of these scenarios will be analyzed as an MRN-NEEM model run, which will produce internally-consistent, integrated projections of key IRP inputs to the standard Ameren Missouri system-level analysis of resource plans.

Following a review of the results and assumptions from previous analysis between Ameren Missouri and CRA, including that performed for Ameren Missouri's 2008 IRP, it was determined that the appropriate variables for probability elicitation were: load growth, carbon policy, and natrual gas prices.

Four other variables were also considered to be potential components of the scenario probability tree[2]. It was determined that the IRP decisions would not be as sensitive to these three variables for the reasons explained below:

- Gross Domestic Product (GDP) – It was determined that uncertainty in this variable would affect IRP outcomes primarily in the way it would affect other critical variables, particularly electricity demand growth and natural gas prices, and thus the IRP-relevant aspects of GDP uncertainty could be folded into the latter two uncertainty representations;

- Lower coal prices – Lower coal commodity prices would tend to be offset by carbon prices under a world with a carbon cap, which we expected would play a high-probability role in the IRP tree. Also, because Ameren Missouri is not modeling new uncontrolled coal as a resource option, the range of uncertainty expected in coal prices is unlikely to substantially affect the choice among the non-coal IRP alternatives;

- Construction costs – Although this variable is expected to influence resource selection it was evaluated as an independent uncertainty in the risk analysis. Construction costs do not have strong interrelated effects compared to the other variables being considered;

- 3-P Emission Prices[3] – Modeling results indicate that, unlike for carbon, wide variations in "3-P" (mercury, SO_2, NO_X) emissions prices have very little impact on IRP-relevant inputs and outputs. The determination to exclude variations in 3-

[2] EO-2007-0409 – Stipulation and Agreement #35; 4 CSR 240-22.070(2)

[3] 4 CSR 240-22.040(8)(D)2.

P policy from the scenario tree was based upon sensitivity analysis conducted for Ameren Missouri's 2008 IRP, in which variations in CAIR and CAMR caps produced insignificant changes to critical IRP drivers. At the time when CRA and Ameren Missouri discussed what variables should be included in the scenario tree both CAIR and CAMR had been remanded, and the form of any replacement legislation was very unclear. For mercury, the political backdrop was gravitating strongly towards a MACT approach and away from cap-and-trade, so the decision was to institute a two-phase mercury reduction requirement (the move to MACT also meant that there was no longer going to be an allowance price for Mercury). However, lacking a specific legislative alternative to CAIR, the CAIR SO_2 and NO_X caps were simulated as originally written. After the MRN-NEEM analysis was completed, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, with more stringent caps. Simultaneously, momentum has gathered behind SO_2 and NO_X MACT requirements triggered by new hazardous air pollutant (HAP) rules. CATR would likely produce higher SO_2 and NO_X allowance prices, but any resulting impacts on critical IRP drivers would not be more influential than the impacts caused by carbon policy, natural gas prices, and load growth. In addition, if CATR were to be paired with MACT requirements for both SO_2 and NO_X, then allowance prices for SO_2 and NO_X might be elevated for one or two years, but would then collapse as all units would be required to add controls thereby making the caps non-binding. Later in the risk analysis Ameren Missouri evaluated more stringent environmental regulations to model the effects on existing plants and the resultant impact on resource needs.

2.3 Assigning Subjective Probabilities

The appropriate individual to assign subjective probabilities is the decision-maker or the person(s) that the decision-maker designates as the best expert(s). Ameren Missouri's management identified several in-house experts to provide the probability distributions for each critical dependent uncertain variable. (Later, senior Ameren Missouri management (the decision-maker) reviewed the resulting subjective probabilities and their basis, and approved them for use in the IRP risk analysis).

CRA structured each probability elicitation session following key principles of sound probability encoding techniques. The process had the following structure.

- First, the purpose of the elicitation process – to minimize natural cognitive biases – was explained, as was the planned use in the IRP of information that would be the subject of the interview. Potential areas of motivational bias were also explored before starting each elicitation. (CRA did not detect any concerns in this regard.)

- Next, the variable to be encoded was defined. The interviewer encouraged the expert to describe events and contingencies that would affect his expectations about the outcome of the uncertain variable. If it became apparent that the expert found that the full uncertainty was too complex to analyze as a whole, the interviewer broke it down into a set of simpler constituent parts, following the structure described by the expert. The formal elicitation was then performed on the various contingent variables. (After the completion of the elicitation, CRA reconstructed the overall probability distribution from the contingent elements and their respective probabilities.)

- Third, the interviewer had the expert identify the specific units for each variable to be encoded, conducted a sequence of "conditioning" questions intended to lessen some common sources of cognitive biases, and used a variety of probability elicitation techniques to obtain quantitative statements that, as a group, described the expert's subjective views on the probability distribution for each variable in question.

- At the conclusion of each interview, CRA showed the expert the produced probability distributions and recapped the experts' general thinking that explained the ranges, areas of likelihood, and contingencies. In each case, CRA verified that these were representative of the expert's beliefs before completing the interview.

There were two experts assigned to each variable. Each was interviewed separately. Such multi-expert elicitations invariably result in different views; indeed, the ability to observe these differences of views is one of the benefits of soliciting information separately from more than one expert. After both had been interviewed, CRA summarized the responses of the two into a comparative format, which was then presented in a conference call to the two individuals together.

Where differences were most pronounced, CRA used the statements from the interviews to highlight what seemed to be the differences in information or perspectives explaining the differences. Discussion of these differences was encouraged, following which the experts were given the opportunity to amend their views in light of the additional discussion. CRA also provided a probability distribution that combined their separate views using equal weights, which could be used in the IRP process, once each expert was fully satisfied with his own individual probability distribution. In this way, CRA developed a single probabilistic statement of potential outcomes for each of the three critical variables that Ameren Missouri's in-house experts agreed was a fair representation of their individual sense of the uncertainty, and the range of opinions across the experts within Ameren. The details and results of those elicitations can be found in Chapter 2 – Appendix A.

lbs/MWh). NO_X emission rates, on the other hand, are rather less dependent on the type of coal being used, and are assumed solely determined by generation technology.

NEEM assumes CO_2 emission rates of 205.3 to 215.4 lbs/MMBtu (depending on the type of coal) for coal-based capacity, with CCS technology achieving a 90% reduction in CO_2 emissions. The CO_2 emissions for natural gas-fired combined cycle (CC) and combustion turbine (CT) units are assumed to be 116.7 lbs/MMBtu. NO_X emission rates range from 0.02 lbs/MMBtu (CC) to 0.08 lbs/MMBtu (CT) among emitting new unit types. These rates, in terms of energy input, are then multiplied by the fully loaded heat rate to produce the emission rates of Table 2.8, given in terms of the electricity produced.

To clarify, consider the CO_2 emission rate given below for IGCC with CCS capacity. NEEM assumes that this technology captures and sequesters 90% of the 212.7 pounds of CO_2 emitted per unit of energy input. Thus, the rate of CO_2 released into the atmosphere from a coal with CCS generator is 21.27 lbs/MMBtu. NEEM assumes a heat rate of 9.713 MMBtu/MWh for this capacity type. As a result, the emission rate for coal with CCS units is equal to the product of 21.27 lbs/MMBtu and 9.713 MMBtu/MWh, equal to 207 lbs/MWh.

The cost of mitigating the emissions of a particular pollutant is dependent upon the emissions rate and the market price of an emissions allowance, Ct. In the cap-and-trade scenarios, the market price of CO_2 is represented by a simple CO_2 price. Recall that there is no explicit price on CO_2 emissions in the Federal Energy Bill, Moderate EPA Regulation, and BAU branches of the probability tree.

Similarly, this analysis does not simulate the disbanded CAMR cap-and-trade scheme for mercury emissions, and, in turn, does not produce allowance prices for mercury. For SO_2 and NO_X emissions, however, NEEM estimates allowance prices against all existing environmental regulations in fully-functioning allowance price markets. These are:

- Title IV/Clean Air Interstate Rule (CAIR) for SO_2 – Title IV melds into the CAIR SO_2 program beginning in 2010 when units in the CAIR region (including units in Missouri) are required to submit two allowances for every ton emitted. This increases to 2.86 allowances per ton emitted in 2015 and beyond;
- CAIR Ozone Season NO_X – the CAIR Ozone Season NO_X program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015 – this cap is applicable for the summer months of May through September;

- CAIR Annual NO_X – the CAIR Annual NO_X program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015.

NEEM dynamically calculates allowance prices for SO_2 and NO_X emissions subject to each of the above constraints. In general, if an emissions cap is binding at any point during the model horizon, the allowance price is equal to the marginal cost of abating one more pound or ton of pollutant.

NEEM allows for banking, so emissions in a given year do not necessarily match the prescribed annual limits of the program, as given in Table 2.9.

Table 2.9 SO_2, NO_X, and Hg Emissions Limits

	SO_2	NO_X	
	Title IV/CAIR	CAIR Ozone	CAIR Annual
Year	Million Tons	Thousand Tons	Million Tons
2010	8.95	568	1.722
2015	8.95	485	1.268
2018	8.95	485	1.268
2020	8.95	485	1.268
2030	8.95	485	1.268

The degree to which the prescribed caps are binding (i.e., the level of emissions), combined with optimal banking choices, sets the equilibrium allowance price. NEEM determines unit-level emissions for SO_2 and NO_X based on unit-specific fuel choices, existing equipment, retrofit choices, and dispatch, the details of which are described below.

SO_2 emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Initial data that is used to calculate SO_2 emissions include the quantity and characteristics of the existing coal fleet, particularly the capacity, existing retrofit equipment, and coal types that can be burned at each unit. NEEM models existing federal SO_2 legislation and rules including Title IV and CAIR. These provide a cap on the level of SO_2 emissions.

The model also includes an estimate of the existing bank of SO_2 allowances entering 2009 (approximately 8.8 million tons) and allows for additional banking or withdrawals from the bank in order to comply with the cap in the most cost-efficient manner possible. The emissions from existing coal units will change over time in response to the SO_2 allowance price projected by NEEM and the SO_2 reduction options available to each unit. Units can reduce their SO_2 emissions in a number of ways.

First, units that do not have a flue gas desulfurization (FGD) retrofit may add one. The cost of these retrofits is a function of the size of the unit and the cost parameters included in Table 2.10.

Table 2.10 Retrofit Costs and Characteristics

All costs are in 2010 dollars.	Reference Size	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Removal Rate
FGD	500	$351	$11.53	$2.13	98%
SCR	243	$234	$0.85	$0.77	90%
SNCR	150	$23.44	$0.35	$1.13	35%
ACI90	250	$2.24	$0.90	$0.61	90%
FPI90	250	$61.55	$1.12	$0.61	90%
CCS (For Coal)	N/A	$1,705	$1.56	$2.76	90%

A unit will add an FGD if the cost of installing the FGD, as measured in dollars per ton of SO_2 removed, is less than the cost of purchasing allowances for that unit over the useful life of the retrofit.

A second option to reduce SO_2 emissions is to change coal types. As shown in Table 2.6, each coal has different SO_2 contents. If a coal can be delivered to the unit then it can switch to burning that coal.

For units that do not currently burn Powder River Basin (PRB) coal, a capital cost would have to be incurred to account for the boiler modifications necessary to burn PRB coals.

Lastly, a unit can reduce its SO_2 emissions by generating less, particularly if SO_2 emissions costs push it higher up the dispatch curve. All new coal units are assumed to include an FGD and therefore have an SO_2 emission rate that reflects 98% removal of inlet SO_2.

NO_X emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Unlike SO_2, NEEM includes initial NO_X emission rates for coal, natural gas, and oil-fired plants. This information is based on NO_X rates reported as part of the EPA's Continuous Emissions Monitoring System (CEMS). As previously described, all emitting units are subject to the caps prescribed by the CAIR NO_X Ozone Season and CAIR NO_X Annual programs.

As with SO_2, there are multiple options for reducing NO_X emissions on existing units. Two retrofits are available to coal units: Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). Units will install these retrofits if the cost per ton of NO_X removed is less than the prevailing NO_X allowance price. The costs and characteristics of SCR and SNCR are included in Table 2.10. The other means through which existing unit can reduce NO_X emissions is by simply generating less. New units, in contrast, are assumed to have controls in place necessary to meet New Source Performance Standards (NSPS). As such, new coal units have a NO_X emission rate of 0.06 lbs/MMBtu, new combined cycle units have a NO_X emission rate of 0.02 lbs/MMBtu, and new combustion turbines have a NO_X emission rate of 0.08 lbs/MMBtu.

Similar to SO_2 emissions, Hg emissions are only from coal-fired units. Hg emissions for any coal unit are a function of the coal burned and the pollution control equipment in place. While there are Hg-specific retrofits, Hg can also be removed as a co-benefit from some non-Hg controls such as FGDs and SCRs.

The Hg co-benefits given in Table 2.11 were provided to CRA by the Electric Power Research Institute (EPRI), and were used as part of comments filed in response to the then-proposed Clear Air Mercury Rule (CAMR).

An earlier table, Table 2.10, lists the two mercury control options available to coal-fired units in NEEM in order to comply with the 60% and 90% mercury reduction requirements in 2015 and 2020.

Table 2.11 Mercury (Hg) Co-Benefits

Equipment in Place			% Removal of Inlet Hg		
PM Control	SO_2 Control	NO_x Control	Bituminous	PRB	Lignite
Fabric Filter	Dry FGD	No SCR	85	25	10
		SCR	90	25	10
	Wet FGD	No SCR	85	75	40
		SCR	90	75	40
	No FGD	No SCR	75	65	10
		SCR	75	65	10
Cold-Side ESP	Dry FGD	No SCR	50	15	10
		SCR	55	15	10
	Wet FGD	No SCR	60	35	35
		SCR	85	35	35
	No FGD	No SCR	35	20	10
		SCR	35	20	10
Hot-Side ESP	Dry FGD	No SCR	0	0	0
		SCR	0	0	0
	Wet FGD	No SCR	55	30	30
		SCR	85	30	30
	No FGD	No SCR	20	0	0
		SCR	20	0	0
Venturi Scrubber	Dry FGD	No SCR	25	15	15
		SCR	60	15	15
	Wet FGD	No SCR	25	15	15
		SCR	60	15	15
	No FGD	No SCR	20	5	5
		SCR	20	5	5

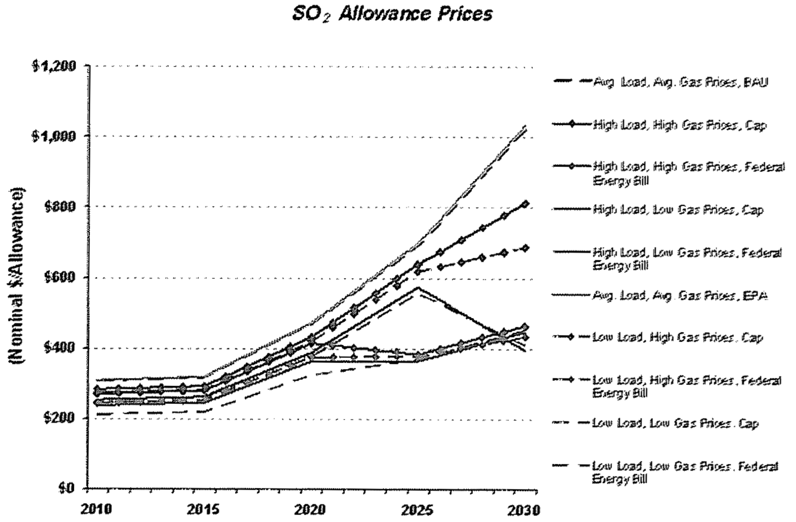
The Activated Carbon Injection (ACI90) technology can only be operated in conjunction with bituminous coal use, and represents a less capital-intensive option for larger units that can rely on existing particulate matter (PM) controls for mercury co-benefits. This ACI90 is only available to units that have already installed a fabric filter. For units without fabric filters, the RPJ90 option is naturally more expensive because it includes the costs of a fabric filter.

With perfect foresight through the end of the modeling horizon, NEEM then optimizes generation patterns, fuel choices and consumption levels, and potential retrofit installations in a manner that minimizes the net present value of total system costs while meeting all reserve margin requirements and complying with all environmental regulations. Allowing for the banking (and subsequent withdrawal) of allowances that could result if permit prices rise faster than the 5% discount rate, NEEM charts an optimal allowance price path through the model horizon.

Again, the resulting allowance price represents the marginal cost of abating one more pound or ton of the pollutant; that is, “Ct,” in the equation shown in the column titled “Mitigation Costs” in an earlier table, Table 2.8.

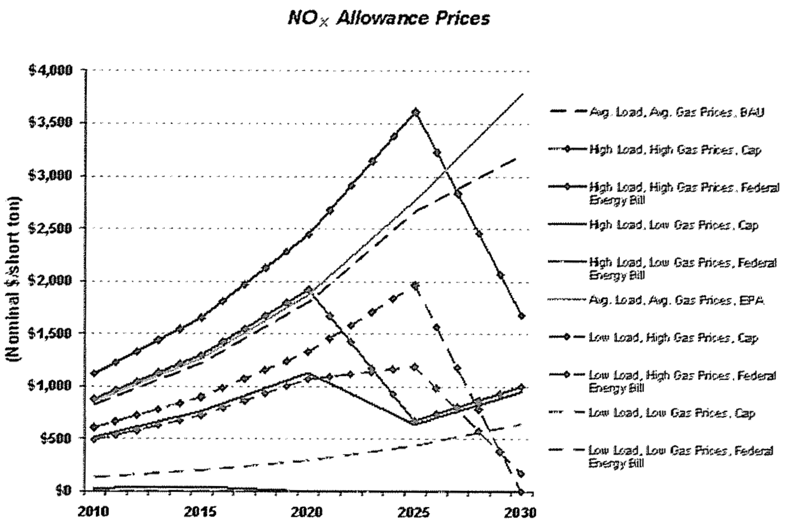
The SO_2 prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.9.

Figure 2.9 SO_2 Allowance Prices



NO_X prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.10. For NO_X allowance prices, Figure 2.10 presents prices under the CAIR NO_X Annual cap.

Figure 2.10 NO_X Allowance Prices



CO_2 permit prices in the cap-and-trade scenarios are shown in Table 2.12.

Table 2.12 CO_2 permit prices

Year	CO2 Price (2010$/metric ton)
2015	$7.50
2020	$17.50
2025	$21.50
2030	$29.25
2035	$37.00
2040	$47.22

Finally, Table 2.13 shows when the SO_2, NO_X, and Hg retrofits are installed on Ameren Missouri coal plants. The year given represents the year when NEEM installs a retrofit on at least half of the unit's capacity.

Table 2.13 SO_2, NO_X, and Mercury Retrofits

Unit	FGD	SCR	ACI90	RPJ90	CCS
Sioux 1	2010			2015	
Sioux 2	2010			2015	
Meramec 1				2015	
Meramec 2				2015	
Meramec 3				2015	
Meramec 4				2015	
Rush Island 1	2020			2015	
Rush Island 2	2020			2015	
Labadie 1	2020			2015	
Labadie 2	2020			2015	
Labadie 3	2020			2015	
Labadie 4	2020			2015	

2.5.8 Electricity Price Forecasts[22]

Forecasts of the market cost of power were derived from MRN-NEEM projections of wholesale electricity prices. The integrated MRN-NEEM modeling framework described in subsections 2.5.1 through 2.5.4 furnishes electricity prices by load block and year for the Eastern Missouri (EMO) region encompassing Ameren Missouri's service territory. This equilibrium electricity price represents the marginal cost of supplying an incremental MWh of electricity in a particular region.

It accounts for (1) the dispatch costs of existing resources and potential new additions, (2) planned maintenance and forced outages at generating units in the region, (3) compliance with all environmental regulations, and (4) a dynamic transmission system that allows for imports and exports between regions. Having sorted all available capacity in a NEEM region by dispatch costs, the model then assesses where the so-constructed supply curve intersects with the demand in a given load block. This determines the wholesale electricity price.

[22] 4 CSR 240-22.050(2)

EXHIBIT 7

Table 8.(3)(e)(3)
Louisville Gas and Electric Company / Kentucky Utilities Company/
Demand Side Management Energy and Demand Impacts

DSM Energy Reduction (GWh)	Status	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential High Efficiency Lighting	Existing	201.8	250.6	299.5	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3
Residential New Construction	Existing	6.9	9.0	11.4	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Residential HVAC Tune Up	Existing	1.9	3.0	4.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Commercial HVAC Tune Up	Existing	2.0	4.2	6.4	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Customer Education & Public Information	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dealer Referral Network	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Responsive Pricing (RRP)	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development & Administration	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Conservation (HEPP)	Enhanced	15.5	20.7	25.9	31.0	36.2	41.4	46.5	51.7	56.8	62.0	67.2	72.3	77.5	82.7	87.8	93.0
Residential Load Management	Enhanced	5.9	9.6	12.8	16.0	18.7	21.4	24.1	26.7	29.4	32.1	34.7	37.4	40.1	42.7	45.4	48.1
Commercial Load Management	Enhanced	0.2	0.4	0.6	0.7	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0
Residential Low Income Weatherization	Enhanced	20.5	23.3	26.1	28.9	31.7	34.5	37.3	46.5	55.7	64.9	74.1	83.3	92.5	101.8	111.0	120.2
Commercial Conservation/Rebates	Enhanced	93.8	150.8	208.8	266.8	324.8	382.7	440.7	495.7	550.7	605.7	660.7	715.7	770.6	825.6	880.6	935.6
Smart Energy Profile	New	29.3	57.0	57.0	104.4	104.4	104.4	104.4	106.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5
Residential Refrigerator Removal	New	3.0	9.0	16.5	24.0	31.4	38.9	46.4	53.9	61.4	68.9	76.4	83.9	91.4	98.9	106.4	113.9
Residential Incentives	New	8.8	20.0	36.9	53.8	70.7	87.6	104.6	120.8	137.1	153.4	169.7	186.0	202.3	218.6	234.9	251.2
Total Annual Energy Reduction	All	389.7	557.6	705.9	901.8	994.9	1,088.1	1,181.2	1,279.1	1,375.1	1,471.0	1,566.9	1,662.9	1,758.8	1,854.7	1,950.7	2,046.6

SC\NRDC EXHIBIT 8

Table 8.(3)(e)(3) Continued

DSM Summer Peak Demand Reduction (MW)	Status	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential High Efficiency Lighting	Existing	14.2	17.5	20.8	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1
Residential New Construction	Existing	2.8	3.5	4.2	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Residential HVAC Tune Up	Existing	0.9	1.3	1.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Commercial HVAC Tune Up	Existing	0.5	1.0	1.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Customer Education & Public Information	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dealer Referral Network	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Responsive Pricing (RRP)	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development & Administration	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Conservation (HEPP)	Enhanced	2.2	3.6	5.1	6.5	8.0	9.4	10.9	12.2	13.5	14.8	16.1	17.4	18.8	20.1	21.4	22.7
Residential Load Management	Enhanced	157.3	171.6	183.9	196.2	206.5	216.7	227.0	237.2	247.5	257.7	268.0	278.2	288.5	298.7	309.0	319.2
Commercial Load Management	Enhanced	5.9	6.7	7.6	8.5	9.1	9.6	10.2	10.8	11.4	12.0	12.5	13.1	13.7	14.3	14.9	15.4
Residential Low Income Weatherization	Enhanced	1.0	1.3	1.6	1.8	2.1	2.4	2.7	3.6	4.5	5.4	6.3	7.3	8.2	9.1	10.0	10.9
Commercial Conservation/Rebates	Enhanced	26.5	47.9	69.7	91.6	113.4	135.2	157.0	177.7	198.4	219.1	239.8	260.4	281.1	301.8	322.5	343.2
Smart Energy Profile	New	5.6	10.9	10.9	19.9	19.9	19.9	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Residential Refrigerator Removal	New	0.4	1.2	2.1	3.1	4.1	5.0	6.0	6.9	7.7	8.6	9.4	10.3	11.1	12.0	12.8	13.7
Residential Incentives	New	2.5	5.7	11.0	16.3	21.7	27.0	32.3	35.3	38.4	41.4	44.5	47.5	50.5	53.6	56.6	59.7
Total Annual Demand Reduction	All	219.6	272.3	320.4	377.6	418.2	458.9	499.5	537.6	575.2	612.9	650.5	688.2	725.8	763.4	801.1	838.7

Table 8.(3)(e)(3) Continued

DSM Winter Peak Demand Reduction (MW)	Status	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential High Efficiency Lighting	Existing	27.8	35.8	43.2	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1
Residential New Construction	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential HVAC Tune Up	Existing	0.1	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial HVAC Tune Up	Existing	0.2	0.4	0.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Customer Education & Public Information	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dealer Referral Network	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Responsive Pricing (RRP)	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development & Administration	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Conservation (HEPP)	Enhanced	0.9	1.4	2.1	3.0	3.9	4.7	5.6	6.5	7.3	8.2	9.1	9.9	10.8	11.7	12.5	13.4
Residential Load Management	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Load Management	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Low Income Weatherization	Enhanced	0.5	1.1	1.8	2.8	4.0	5.4	7.0	8.9	10.8	12.6	14.5	16.4	18.2	20.1	21.9	23.8
Commercial Conservation/Rebates	Enhanced	9.5	17.2	24.9	32.5	40.2	47.9	55.5	63.2	70.9	78.5	86.2	93.9	101.5	109.2	116.8	124.5
Smart Energy Profile	New	4.9	9.7	9.7	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Residential Refrigerator Removal	New	0.4	1.3	2.3	3.4	4.4	5.5	6.5	7.6	8.6	9.7	10.7	11.8	12.8	13.9	14.9	16.0
Residential Incentives	New	1.2	2.6	4.8	6.9	9.0	11.2	13.3	15.4	17.5	19.7	21.8	23.9	26.1	28.2	30.3	32.5
Total Existing Programs	All	45.6	69.7	89.8	117.8	130.8	143.9	157.2	170.8	184.4	198.0	211.5	225.1	238.7	252.3	265.8	279.4

Louisville Gas and Electric Company / Kentucky Utilities Company

DSM Program Review

Report

March 18, 2011

09-110

SC\NRDC EXHIBIT 9

ICF INTERNATIONAL

Louisville Gas and Electric Company / Kentucky Utilities Company

DSM Program Review

Report

March 18, 2011

Prepared for:
Louisville Gas and Electric Company /
Kentucky Utilities Company
220 West Main Street
Louisville, KY 40202
Prepared by:
ICF International
620 Folsom Street, Suite 200
San Francisco, CA 94107
(415) 677-7100

Table of Contents

List of Figures

List of Tables

Executive Summary

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), and, hereafter referred to as "LG&E / KU" or the "Companies", engaged ICF to provide a broad review of their demand side management (DSM) plan for 2011 to 2017. This review included a detailed overview of existing programs that the Companies are enhancing and re-filing, and new programs. ICF also conducted a portfolio-level review of the Companies' overall DSM investments. Specifically, the Companies engaged ICF to:

1. Review the DSM planning materials and process as documented by the Companies.
2. Review the individual program designs developed by the Companies.
3. Compare the planning process and individual DSM program designs to known best practices and appropriate peer utilities.
4. Identify any gaps or shortcomings in the process or program designs, including specific recommendations regarding alternative approaches or designs.
5. Participate in program design and planning discussion as may be required by the Companies.
6. Prepare a report summarizing the review and providing a third-party opinion regarding the sufficiency of the process and designs.

This report is the culmination of ICF's work for this project and represents the summary report detailed in Task 6 above.

Regulatory and Policy Environment

The market for energy efficiency is evolving quickly, and nowhere in the country is this more evident than in Kentucky. Since ICF's last review of the Companies' programs in 2007, both state and federal policies have shifted strongly in favor of energy efficiency. At the state level, this was driven by Kentucky Governor Steven Beshear, who has placed energy efficiency squarely at the top of his Seven Point Energy Strategy. At the federal level, this was driven largely by the passage of 2009 American Reinvestment and Recovery Act (ARRA, or "the Stimulus package"). ARRA outlayed more than $16 billion nationwide in energy efficiency and related investments; Kentucky is slated to receive over $150 million during the three-year period spanning 2009-2011.

Commensurate with federal and state policy agendas, the Companies have made energy efficiency a high priority in their corporate strategies. In 2008, the Companies appointed a new Customer Energy Efficiency Management team, including a new director and two new department managers. The Companies also hired four additional program managers to manage new programs, and three new researchers/program analysts. These human resource investments represent a significant commitment to energy efficiency that will leave the Companies well-positioned to successfully grow their DSM portfolio in the future.

The Companies are also developing a DSM portfolio that is consistent with many of the specific actions outlined in the Governor's plan. By undertaking this review, the Companies are committed to incorporating best practices into their programs. In addition, with the new programs, the Companies are addressing the potential for energy efficiency in both the mass market and in targeted end uses.

Best Practices

Energy efficiency program *best practice* is much more a term of art than science; there simply is too much variability across objectives, regulatory structures, and program types to enable simple broad conclusions about what is *best*. Typically, best practice is considered a function of program result, such as whether the program met or exceeded its objectives. An alternative view of best practice focuses on the design and execution of essential program elements, such as marketing, service delivery, program back office efficiency, etc. For example, though a particular program might not have delivered particularly strong overall results, certain elements of its structure, such as incentive fulfillment, might be considered best-in-class. Alternatively, while difficult, it is not unheard of for a program based on inefficient or flawed processes to nevertheless deliver outstanding results.

In general, best practice programs and portfolios seek to achieve each of the following goals:

- Provide programs that are cost-effective.
- Provide a portfolio that covers hard-to-reach markets.
- Provide program budgets that are sufficient to deliver the programs effectively to market.
- Provide programs that have sufficient budgets for marketing, training and education (market transformation activities).
- Provide a portfolio that strikes an appropriate balance of mitigated risk, proven program types, and more innovative programs.
- Provide a portfolio that is flexible enough to adapt to changing market conditions in a cost-effective manner.
- Provide an evaluation, measurement, and verification (EM&V) budget for each program, and plans for program evaluations on a regular basis.

Portfolio Review

The Companies' programs satisfy each of the best practice criteria listed above. In addition, the Companies' projected program costs and savings compare favorably to the rest of the country. The Companies' overall cost of savings, expressed in dollars per first year kWh, are projected to be less expensive that the median cost of savings achieved by program administrators in the South, the Midwest, and the U.S. as a whole. In addition, the level of savings achieved by the Companies, expressed both as a percentage of annual kWh sales, and annual kW peak demand, also exceeds that of their peers.

Because the programs easily pass standard cost-effectiveness tests, and participants gain significant benefits from the programs, the Companies should continue to design and market the programs broadly, in order to increase participation and minimize the number of non-participants.

Overall Conclusions

Our review of the Companies' programs, and the context in which they were developed, leads us to the following conclusions:

- The Companies' proposed portfolio appropriately addresses evolving federal and state policies. In addition, the portfolio contains many elements of best practices, including cost-effectiveness, broad targeting, and flexible design.
- The Companies should commission a potential study or market characterization study, an action item the governor has also proposed for the state in his energy plan. The study results could be used to help plan programs that capture savings where potential is greatest and/or most cost-effective.
- Based on a market characterization study of the commercial sector, develop additional programs targeting the commercial sector.
- The Companies should continue to market their successful load control program, and offer additional demand response options.
- With their Residential Conservation/Home Energy Performance and Low Income Weatherization (WeCare) programs, the Companies should continue to leverage federal and statewide resources, where applicable, in order to maximize available funding and supplement existing program participation.
- As behavior-based programs gain entry into utility portfolios, the Companies should develop relationships with program implementers and utility program managers in order to learn from others' experiences, and adjust the design and delivery of their own behavior-based initiatives, including the Smart Energy Profile program.
- Coordinate and cross-promote their new residential programs with existing residential programs.

1. Introduction

1.1. Scope of ICF's Review

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), and, hereafter referred to as "LG&E / KU" or the "Companies", engaged ICF to provide a broad review of their demand side management (DSM) plan for 2011 to 2017. This review included a detailed overview of existing programs that the Companies are enhancing and re-filing, and new programs. ICF also conducted a portfolio-level review of the Companies' overall DSM investments. Specifically, the Companies engaged ICF to:

1. Review the DSM planning materials and processes as documented by the Companies.
2. Review the individual program designs developed by the Companies.
3. Compare the planning processes and individual DSM program designs to known best practices and appropriate peer utilities.
4. Identify any gaps or shortcomings in the process or program designs, including specific recommendations regarding alternative approaches or designs.
5. Participate in program design and planning discussion as may be required by the Companies.
6. Prepare a report summarizing the review and providing a third-party opinion regarding the sufficiency of the process and designs.

1.2. ICF's Approach

The review began with a kick-off meeting during which ICF and the Companies discussed and clarified the objectives of the project. ICF discussed its approach to the review and provided the Companies with a data request that outlined the materials ICF required to complete the review, including: the Companies' draft DSM filing; load forecasts; integrated resource plans (IRPs); DSM program modeling inputs and outputs; and relevant reports produced by the State of Kentucky, including Governor Beshear's Energy Strategy.

Our review consisted of both bottom-up and top-down approaches. From the bottom-up, we reviewed each of the Companies' proposed programs against program best practices from around the country. These program-level reviews focused primarily on program delivery (e.g. how programs are marketed, to whom incentives are paid, etc.), but also examined key program metrics for reasonableness (e.g. program costs are appropriate for this program given market maturity in Kentucky). The top-down review included an analysis of portfolio level metrics (e.g. kWh savings as a percentage of sales) against the Companies' peers, a gap analysis to identify potential lost savings opportunities, and a portfolio best practices analysis to determine whether the Companies' proposed DSM portfolio:

- Is cost-effective;
- Targets markets and technologies where the largest potential exists;
- Targets hard-to-reach markets;
- Has sufficient marketing and education budgets -- incentives are only one aspect of a program;
- Is flexible enough to adapt to changing market conditions;
- Has an appropriate mix of proven and innovative programs;

- Has an appropriate mix of energy and demand programs; and,
- Has new and modified programs that were selected through an appropriate planning process.

1.3. Report Overview

The remainder of this report is organized into the following sections: Section 2: Regulatory and Policy Environment; Section 3: Best Practices; Section 4: Portfolio Review; Section 5: Program Reviews; Section 6: Overall Conclusions.

Additional description for each section is provided below.

Section 2: Regulatory and Policy Environment explains current federal and state policy with regards to energy efficiency. The current policies help explain the context in which this report was developed. This section also includes a summary of how the Companies are responding to policy shifts. As these policies evolve, and especially as federal climate change legislation moves closer toward regulatory certainty, the Companies will need to keep abreast of these developments, and re-evaluate programs and portfolios to ensure materiality, compliance, and effectiveness.

Section 3: Best Practices defines "best practice" generally as well as how it is used in this report. As noted previously, "best practice" is a subjective label that is context-sensitive. ICF believes that the reviews included in Section 5 should be viewed as a comparative exercise, with caution given to differences in the market, climate, and administration. For each program review, several suggestions as to how the Companies can continue to improve their programs through design and delivery adjustments are offered. In addition, suggestions relating to increased engagement with national program sponsors (such as the EPA), statewide agencies, and other local stakeholders, where applicable are included.

Section 4: Portfolio Review conducts a brief overview of the Companies' complete DSM portfolio, including existing programs that were not subject to a best practice review. The portfolio is compared to its peers in the South, the Midwest, and the U.S. as a whole. In contrast with Section 3, this section contains a more quantitative comparison of portfolio savings and costs. This section also contains a discussion of regulatory treatment of program costs, and the impact of the portfolio on ratepayers.

Section 5: Program Reviews contains the reviews for enhanced existing and new programs. Each review begins by describing the Companies' existing program and proposed enhancements, if applicable. The review then describes a selection of best practice programs, and compares the Companies' programs using a variety of metrics. Finally, the review takes assessment of the differences, summarizes ICF's conclusions, and, if necessary, offers suggestions as to how to incorporate these in the future.

Section 6: Overall Conclusions includes conclusions drawn from the introduction, and recaps the individual program conclusions and suggestions contained in Section 5.

2. Regulatory and Policy Environment

The market for energy efficiency is evolving quickly, and nowhere in the country is this more evident than in Kentucky. Since ICF's last review of the Companies' programs in 2007, both state and federal policies have shifted strongly in favor of energy efficiency. At the state level, this was driven by Kentucky Governor Steven Beshear, who has placed energy efficiency squarely at the top of his Seven Point Energy Strategy. At the federal level, this was driven largely by the passage of 2009 American Reinvestment and Recovery Act (ARRA, or "the Stimulus package"). ARRA outlaid about $16.6 billion nationwide in energy efficiency and related investments; Kentucky is slated to receive over $150 million during the three-year period spanning 2009-2011.

Below is a discussion of these and other policy shifts in greater detail, the implications for the Companies' programs, and the Companies' response to this changing political environment.

2.1. Federal

There were three major developments at the federal level since ICF reviewed the Companies' portfolio in 2007. Below, are highlights of key Federal developments that have the potential to impact the Companies' DSM programs.

1. *Under cap-and-trade scenarios in pending legislation, DSM should become more cost-effective for the Companies.* However, a specific cap-and-trade scenario is unlikely to be implemented until 2011, and possibly even later. Possible options include:

    a. The American Clean Energy and Security (ACES) Act (H.R. 2454) was passed by the House of Representatives on June 26, 2009. ACES establishes a cap-and-trade program covering most U.S. greenhouse gas emissions (GHGs), a federal renewable electricity and energy efficiency standard (RES), new efficiency requirements, power plant performance standards, and other complementary measures. However, the Senate has not considered this bill and is unlikely to do so in the near future.

    b. The Senate has two other bills under consideration. The first, the Clean Energy Jobs and American Power Act (S. 1733), introduced on September 30, 2009, contains most of the same provisions as ACES with a few changes and some strategic omissions. A modified version of this bill, known as the American Power Act, has been discussed but not formally introduced. The second, Carbon Limits and Energy for America's Renewal (CLEAR) Act (S. 2877), was introduced on December 11, 2009. This "cap-and-dividend" bill would tax carbon emitters and use the revenues to provide refunds to affected ratepayers. The first bill is considered more feasible, though the actual date of passage for either bill is uncertain, and unlikely to occur in the near future.

    c. The EPA is moving forward with regulation of GHGs through the Clean Air Act (CAA), primarily through existing permitting rules that apply mostly to manufacturing facilities but also to some electricity generators. Future regulatory action by the EPA may be determined or limited by the Congress, such as legislation that would pre-empt the EPA from using the CAA to regulate GHGs.

2. *The Stimulus package provided unprecedented resources for energy efficiency and DSM nationwide.* The 2009 ARRA authorized about $16.6 billion in energy efficiency

funding that qualifying public entities—primarily states, cities, and counties—could pursue. The primary objectives of this funding are to create jobs, save energy, and build clean energy (energy efficiency and renewable energy) infrastructure for the longer term. The Department of Energy's (DOE) major allocations to Kentucky (over 2009-2011) include:

a. $70.9 million in Weatherization Assistance Program (WAP) funding;

b. $52.5 million in State Energy Program (SEP) funding;

c. $25.1 million in Energy Efficiency and Conservation Block Grants (EECBG); and,

d. $4.1 million in Energy Efficient Appliance Rebate Program funding.

In sum, this is approximately $50 million in average annual funding for energy efficiency programs in Kentucky. In 2008, the *total* energy efficiency program spending in Kentucky was $24 million.

3. *As compact fluorescent lamps (CFLs) become the baseline technology, obtaining cost-effective program savings will be more challenging.*[1] Federal lighting standards, including those for many popular lighting products like CFLs, will start to phase-in during 2012, which will diminish the impact of today's efficient lighting technologies.

2.2. State

Governor Beshear made energy efficiency a top priority within his energy strategy, *Intelligent Energy Choices for Kentucky's Future*. In this document, the governor set forth the following goal:

> *Energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand.*[2]

This amounts to reducing statewide energy consumption by an average of about 1 percent per year through 2025, an ambitious goal that would place Kentucky in the top tier of states in the Midwest and South in terms of DSM performance.

The governor's overall plan proposes to enact a renewable and efficiency portfolio standard (REPS) that would be set at 25 percent of the state's projected energy use in 2025. In addition to reducing projected emissions in 2025 by 50 percent, the REPS would also reduce emissions by 20 percent relative to the 1990 baseline. This aggressive goal surpasses the targets set by California's AB 32 law (2020 emissions equal to 1990), and New England's Regional Greenhouse Gas Initiative (2018 emissions 10 percent lower than 2009), and compares to the European Union's Emissions Trading Scheme (2020 emissions 20 percent lower than 1990).

[1] The Energy Independence and Security Act of 2007 (the "Energy Bill"), signed into law by President Bush on December 18, 2007, requires all light bulbs use 30 percent less energy than today's incandescent bulbs by 2012 to 2014. The phase-out will start with 100-watt bulbs in January 2012 and end with 40-watt bulbs in January 2014. By 2020, a Tier 2 would become effective, which requires all bulbs to be at least 70 percent more efficient (effectively equal to today's CFLs).

[2] Governor Steven L. Beshear. Intelligent Choices for Kentucky's Energy Future. November 2008. p. vi.

The governor's plan proposes that energy efficiency can be the primary method strategy to meet the REPS goal. Energy efficiency would offset 18 percent of the state's projected energy demand, with the remaining 7 percent coming from renewable energy and bio-fuels. In addition to the REPS that would apply to the state's utilities, the governor proposes that additional savings would result from aggressive energy savings targets for state government. The energy efficiency portion of the REPS would also include a comprehensive education, outreach, and marketing component by the state.

As a first step, the governor authorizes the Public Service Commission (PSC) to institute a proceeding that examines the impacts of an REPS. This proceeding will also identify cost-effective programs, and include recommendations for implementing them. The governor also encourages and authorizes the PSC to commit greater resources to DSM, including rules that would require the utilities to implement best practice programs, standardization of the rules regarding industrial customer opt-outs, and an increased focus on the evaluation of DSM programs. As a longer term action item (four to seven years from the plan's inception), the governor also encourages the PSC to work with the utilities on a smart grid policy.

2.3. How Is LG&E / KU Responding to State and Federal Policy Shifts?

2.3.1. Energy Efficiency is a Priority for the Companies' Upper Management

Commensurate with federal and state policy agendas, the Companies have made energy efficiency a high priority in their corporate strategies. In 2008, the Companies appointed a new Customer Energy Efficiency Management team, including a new director and two new department managers. The Companies also hired four additional program managers to manage new programs, and three new researchers/program analysts. These human resource investments represent a significant commitment to energy efficiency that will leave the Companies well-positioned to successfully grow their DSM portfolio in the future.

The Companies are also developing a DSM portfolio that is consistent with many of the specific actions outlined in the Governor's plan. By undertaking this review, the Companies are committed to incorporating best practices into their programs. In addition, with the new programs, the Companies are addressing the potential for energy efficiency in both the mass market and in targeted end uses.

2.3.2. LG&E / KU's Portfolio Is Growing and Diversifying

Table 1 and Figures 1-3 below help illustrate the recent evolution of the Companies' DSM portfolio.

- Column *b* in Table 1, "Target Sectors(s)" indicates the Companies' designations of the target market(s) for the programs in column *a*.
- Column *c*, "Program Status" includes:
    - Existing programs – Programs currently administered by the Companies that are not being modified substantially and re-filed in their DSM Plan;

- Enhanced programs - Programs currently administered by the Companies that are being modified substantially and re-filed in their DSM Plan; and,
- New programs that the Companies are proposing in their DSM Plan.

- Column *d* is an ICF-designated program label. Column *d*, "Program types," includes:
  - Resource acquisition – Programs designed primarily for the purpose of implementing efficiency measures in the marketplace;
  - Education and/or marketing – Programs designed primarily to educate the public about the Companies' DSM offerings, other efficiency programs (i.e. State and Federal), and energy efficiency, generally; and,
  - Low income – Programs that implement efficiency measures, but for which only qualified low income households are eligible.

- Column e is also an ICF-designated program label. Column *e*, "Risk/innovation," includes designations, based on ICF's professional judgment of the investment risk and degree of innovation in design, delivery, and technologies associated with each program. A risk/innovation designation of *low/low* means that on the risk side, the program is a very safe investment because the program is well-understood and is a proven design that has become a best practice by performing successfully (cost-effectively) in a variety of jurisdictions. On the innovation side, *low* means that the design, delivery, and technologies that comprise the program are widely understood and used successfully in programs in most jurisdictions.

  Conversely, a risk/innovation designation of *high/high* means on the risk side there is considerable uncertainty about the program's performance, either because the program has not been implemented before, or if it has, there is very little science or evaluation around program savings. On the innovation side, this means the program will employ delivery methods, technologies, or both that are novel, or at least whose performance is not well understood, but also have the potential (based on theory or pilot studies) to achieve significant savings levels.

Table 1: Existing, Revised, and New LG&E / KU Programs ("The Portfolio")

a	b	c	d	e	f	g
Program	Target Sector(s)	Program Status	Program Type	Risk/ Innovation	Year 1 Budget	Year 1 Savings (MWh)
Residential High Efficiency Lighting	Residential	Existing	Resource Acquisition	Low/Low	$3,416,046	65,150
Residential New Construction	Residential	Existing	Resource Acquisition	Med/Low	$1,102,635	2,297
Residential HVAC Tune Up	Residential	Existing	Resource Acquisition	Low/Med	$487,332	1,072
Commercial HVAC Tune Up	Commercial	Existing	Resource Acquisition	Low/Med	$411,778	1,942
Customer Education & Public Information	Res. and Com.	Existing	Education and/or Marketing	Med/Low	$3,296,660	0
Dealer Referral Network	Res. and Com.	Existing	Education and/or Marketing	Low/Med	$152,056	0
Residential Responsive Pricing (RRP)	Residential	Existing	Resource Acquisition	Med/High	$125,000	0
Program Development & Administration	Res. and Com.	Revised	Program Development & Admin.	Low/Low	$1,260,457	0
Residential Conservation (HEPP)	Residential	Revised	Resource Acquisition	Med/Med	$1,460,826	2,948
Residential Load Management	Residential	Revised	Resource Acquisition	Low/Low	$6,186,874	1,868
Commercial Load Management	Commercial	Revised	Resource Acquisition	Low/Low	$321,821	107
Residential Low Income Weatherization	Residential	Revised	Low Income	Low/Low	$2,368,462	2,632
Commercial Conservation/Incentives	Commercial	Revised	Resource Acquisition	Low/Low	$3,255,400	54,988
Smart Energy Profile	Residential	New	Resource Acquisition	Med/High	$1,370,800	29,664
Residential Refrigerator Removal	Residential	New	Resource Acquisition	Low/Low	$815,800	3,000
Residential Incentives	Residential	New	Resource Acquisition	Med/Low	$1,567,352	8,544
Total					$27,599,300	174,211

Figure 1 illustrates the distribution of the Companies' Year 1 portfolio budget across program status categories. Eighty six percent (86%) of the budget is earmarked for programs the Companies are currently operating, including existing and revised programs. The revised programs include program enhancements that the Companies believe will improve program performance, either because the Companies received feedback on the program through formal evaluation, or because after some time in the market, program staff sees opportunities that the current program is not capturing. By adapting to the marketplace through the modification of existing programs and making forays into the marketplace with new programs, the Companies demonstrate that they are seeking to improve and grow the portfolio.

Figure 1: Distribution of Year 1 Program Spending, by Program Status

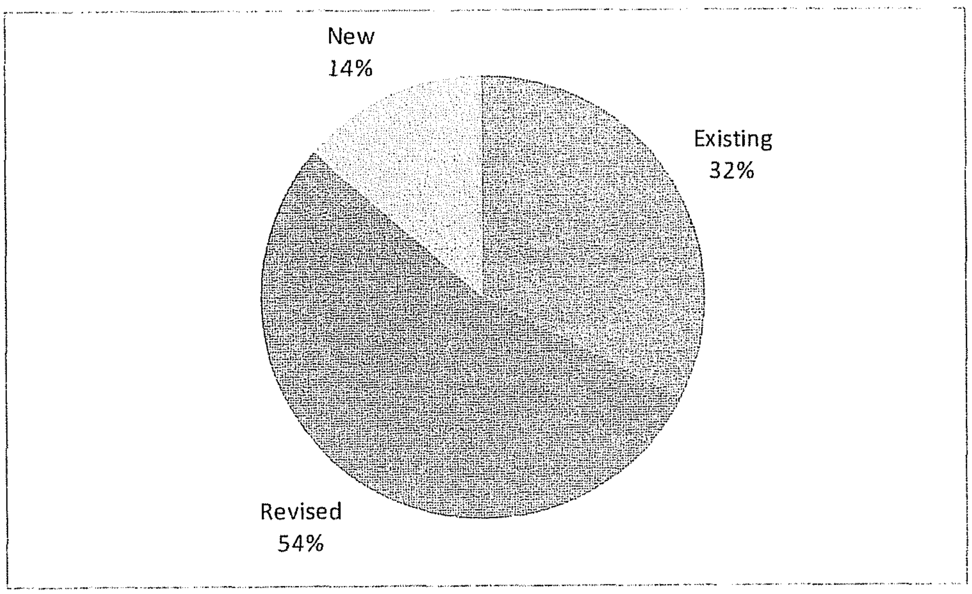


Figure 2 illustrates that the Companies will spend a large majority of their budget in Year 1 on programs designed primarily to acquire savings. It is important to note that this figure does not show the full extent of the Companies' planned marketing budget; each program budget includes funding for marketing and education activities.

Figure 2: Distribution of Year 1 Program Spending, by Program Type

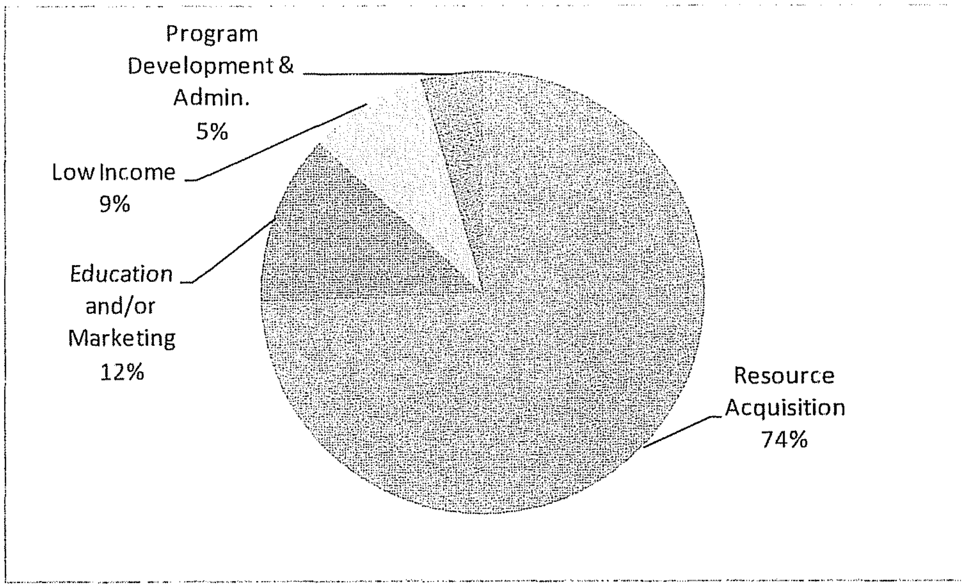
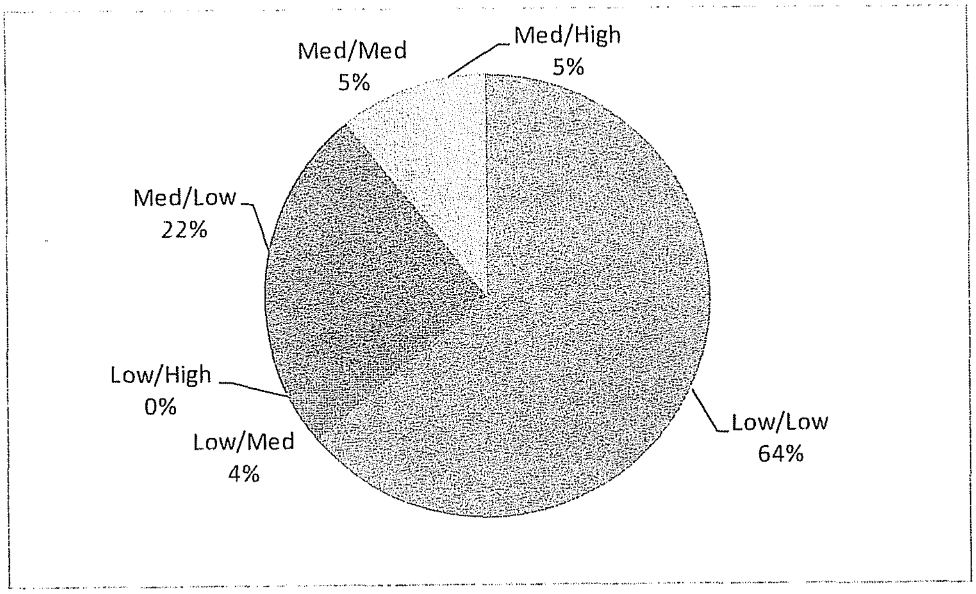


Figure 3 illustrates that the Companies' Year 1 portfolio is largely a low-risk investment, though the portfolio also includes some more innovative, though riskier elements. Overall, ICF believes that the Companies' proposed Year 1 portfolio is a relatively conservative investment that strikes an appropriate balance between low-risk programs that are well-understood (e.g. Residential HVAC-Tune Up and Commercial Conservation Rebates) and programs that have some innovative elements and are more forward looking (e.g. Smart Energy Profile and Residential Responsive Pricing), but are also more risky in that program performance is more uncertain. ICF does not characterize any of the Companies' programs as being a high risk investment.

Figure 3: Distribution of Year 1 Program Spending, by Risk/Innovation Category



3. Best Practices

3.1.1. Defining Best Practice

Energy efficiency program *best practice* is much more a term of art than science; there simply is too much variability across objectives, regulatory structures, and program types to enable simple broad conclusions about what is *best*. Typically, best practice is considered a function of program result, such as whether the program met or exceeded its objectives. An alternative view of best practice focuses on the design and execution of essential program elements, such as marketing, service delivery, program back office efficiency, etc. For example, though a particular program might not have delivered particularly strong results overall, certain elements of its structure, such as incentive fulfillment, might be considered best-in-class. Alternatively, while difficult, it is not unheard of for a program based on inefficient or flawed processes to nevertheless deliver outstanding results.

Best practice should be viewed partly as a function of the experience of the program administrator and implementer. What is best practice for a utility that has been designing and managing programs for two decades will be different in some cases from what should be viewed as best for an organization just entering the field. For example, ICF could not find one program *exactly* comparable to the Companies' proposed Residential Rebates program, but this is only because the Companies are packaging particular elements of their residential portfolio differently than other utilities. The programs that are often cited as best practice in other states (including California, New York, Oregon, Texas, Vermont, and Wisconsin) package some aspects of their portfolios in radically different ways. Although the Companies should look to these best practice states for ideas, ultimately the Companies must design a package that works best in *their own* markets.

In general, best practice programs and portfolios seek to achieve each of the following goals:

- **The programs are cost-effective.** Although cost-effectiveness can be defined in several ways, the most common method for investor-owned utilities to use is based on the California Standard Practice Manual tests. The manual contains four tests, the most comprehensive of which is the Total Resource Cost test. This test compares the net present value (NPV) of benefits (energy and demand savings multiplied by the value of avoided energy costs), with the NPV of costs (utility program costs and program participants' costs) over the lifetime of the implementation of DSM programs. If the benefit-cost ratio is greater than or equal to one (1.00), then the program provides a net benefit to the utility's ratepayers.
- **The portfolio covers hard-to-reach markets.** The portfolio must include programs that are targeted toward hard-to-reach segments, which typically include low-income and small commercial customers. Both of these customer segments face additional barriers to participation in DSM programs, including the *split incentive*. This term signifies the case where a customer would benefit from a lower utility bill but often lacks the authority to install energy-saving equipment in his leased residence or place of business.
- **Program budgets are sufficient to deliver the programs effectively to market.** Program budgets must be constructed to offer market-based incentives that will result in the expected level of participation. In addition, the budget should reflect any necessary increase of internal staffing or the use of an implementation contractor, and sufficient budgets for non-incentive and non-implementation costs (see below). In addition, program budgets should be monitored or adjusted annually to prevent over- and under-subscription of program funds.

- **Programs have sufficient budgets for marketing, training and education (market transformation activities).** A program that contains adequate funding for these activities can help customers and trade allies overcome the information barrier that is typical of energy efficiency investments. In addition, funds spent on information-related initiatives can pay dividends in the long term, when market transformation begins to take effect.
- **The portfolio strikes an appropriate balance of less risky, proven program types, and more innovative programs.** A less mature market would require more proven program types that have been implemented throughout the country, such as lighting and HVAC programs in both the residential and commercial sectors. Over time, as the market matures and savings potential decreases, new and innovative programs can be implemented. These programs can often develop from prior pilot programs or information initiatives, and can be co-marketed with proven program types.
- **The portfolio is flexible enough to adapt cost-effectively to changing market conditions.** A flexible and broad portfolio design will target all customer segments, and include a variety of program types (including rebates, direct install, demand response incentives, etc.) and energy efficiency measures (retrofit, replace-on-burnout, or new). This will ensure that economic conditions that negatively impact one customer segment will not affect the entire portfolio.
- **Evaluation, Measurement and Verification (EM&V) is budgeted for and the Companies have plans to have programs evaluated on a regular basis.** An adequate EM&V budget that results in timely process and impact evaluations should result in a feedback loop that validates program results and helps informs long-term program adjustments and design.

4. Portfolio Review

Portfolio Review Criteria	Summary Review
Intelligent Energy Choices for Kentucky's Future	
Programs will make progress toward the goal of reducing energy consumption in Kentucky by at least 18 percent below currently projected 2025 energy consumption.	Yes. The Companies' proposed portfolio savings are projected to achieve more than 0.5 percent of annual sales in Year 1. Greater savings levels may be achieved through the introduction of additional program targeting the commercial sector.
Industry Best Practice	
Programs are cost effective.	Yes. The portfolio is cost-effective from the perspective of all ratepayers (based on the results of the TRC test), the utility (based on the results of the UCT test), and program participants (based on the results of the Participant Test). Vis-à-vis the generation alternative, this portfolio will have a lower impact on customer rates over the long-term, based on the results of the UCT test.
The portfolio covers hard-to-reach markets.	Yes. The WeCare program, which targets low income customers, represents 9 percent of the total portfolio budget, increasing to 20 percent by Year 7. Further, there are a variety of other offerings that help make efficiency investments more affordable to low income customers and small businesses, including the Companies' Residential High Efficiency Lighting program, the Commercial Conservation program, and the Commercial Load Management program.
Program budgets are sufficient to deliver the programs effectively to market.	Yes. The Companies' programs are adequately sized. The programs include the necessary funds both for incentive and implementation costs. In addition, funding is consistent from year to year, which ensures program success.
Programs have sufficient budgets for marketing, training and education (market transformation activities).	Yes. The budget contains line items for each of these cost types.
The portfolio strikes an appropriate balance of less risky, proven program-types, and more innovative programs.	Yes. The Companies have a generally conservative approach to portfolio planning that is appropriate given that the market is fairly immature. Nonetheless, the Companies are making forays into more innovative, albeit more risky programs, which have the potential to capture high energy savings. This includes the social marketing-based program *Smart Energy Profile*. As a result, the Companies will be well-positioned to implement cutting-edge programs as their advanced metering infrastructure moves from planning to deployment.

Portfolio Review Criteria	Summary Review
The portfolio is flexible enough to adapt cost-effectively to changing market conditions.	Yes. One example of this is that 54 percent of the Companies' Year 1 budget is for existing programs that are being modified based on evaluations and/or the Companies' experience. The Companies have built flexibility into their program designs and is adapting programs to changing market conditions.
EM&V is budgeted for and the Companies have plans to have programs evaluated on a regular basis.	Yes. In the past, the Companies have had their programs evaluated on a regular basis, and have cancelled or adapted programs based on feedback from evaluators. Program budgets include EM&V.

4.1. Benchmarking Costs and Savings

The Companies' projected program costs and savings compare favorably to the rest of the country. Table 2 below compares the Companies' overall cost of savings, expressed in dollars per first year kWh, are projected to be less expensive that the median cost of savings achieved by program administrators in the South, the Midwest, and the U.S. as a whole.

The level of savings achieved by the Companies, expressed as a percentage of annual kWh sales, also exceeds that of their peers.[3] In Year 1, the Companies' projected programs savings will equal nearly 0.5 percent of annual sales, which is a significant step toward achieving the governor's savings goal.

Table 2: LG&E / KU's Energy Portfolio Performance versus the South, Midwest, and U.S. Median

Portfolio Metric	LG&E / KU Year 1	LG&E / KU Year 3	LG&E / KU Year 5	Southern Region Median (2008)[a]	Midwest Region Median (2008)[a]	U.S. Median (2008)[a]
$ per 1st year kWh	$0.16	$0.19	$0.17	$0.89	$0.47	$0.33
Annual kWh savings as % sales	0.5%	0.5%	0.5%	0.1%	0.1%	0.4%

[a]U.S. EIA Form 861 Data (2008); Program Administrator spending;
$1 million or more annually on DSM programs.

In addition, the level of savings achieved by the Companies, expressed as a percentage of annual kW peak demand, also exceeds that of their peers. The benchmarking study cited below was composed primarily of Midwest utilities; LG&E / KU's cost per kW, due to its successful demand response programs, is also lower than its peers.

[3] 2008 is the most recent year for which EIA Form 861 data is available.

Table 3: LG&E / KU's Demand Portfolio Performance versus Benchmarking Study

Portfolio Metric	LG&E / KU Year 1	LG&E / KU Year 3	LG&E / KU Year 5	Bench-marking Median (2007)[b]
$ per 1st year kW	$566	$682	$605	$836
Annual kW savings as % demand	0.7%	0.8%	0.8%	0.6%

[b]Summit Blue DSM Benchmarking Study. Greater Impacts at Reasonable Costs ACEEE Summer Study, 2008

Portfolio-level metrics are a useful way to ensure that portfolio planning estimates are comparable to benchmarking and best practice studies. However, since the program mix in utility portfolios is dependent on numerous factors, including the level of market maturity, generation costs, and customer receptivity, caution should be exercised when attempting to compare a portfolio with best practice. Instead, a high-level portfolio view should be used in concert with more detailed views of individual programs.

4.2. Program Spending, by Sector

One way for the Companies to achieve even greater savings levels in the future is to target a greater percentage of their program spending on the commercial sector. Table 4 below shows estimated electricity consumption in the Companies' territories, by sector (excluding industrial), as well as projected DSM program spending levels and program costs. Residential customers consume approximately 50 percent of electricity but residential program spending is about 86 percent of total DSM program spending between Years 1 and 7.

ICF's experience is that allocation of program spending by sector is a complicated and highly political issue in most jurisdictions. Utility commissions and program administrators must balance the need to meet aggressive state savings goals against other policy priorities, including the need to target hard-to-reach populations (e.g. low income customers and small businesses), as well as the interests of ratepayer advocates, environmental organizations, the State Attorney General, and others. The Companies' proposed spending by sector may be entirely appropriate given Kentucky's political economy; however, strictly from the standpoint of potential energy savings, greater program spending on the commercial sector should result in higher-than-projected savings for the Companies. Additional spending on the commercial sector would also be cost-effective, as commercial programs tend to be less expensive than residential programs because businesses have the needs and means to make larger DSM investments than residential customers.

In discussing this topic with the Companies' staff, ICF learned that the Companies do recognize the potential within the commercial sector and, in the future, may file additional programs targeted at commercial customers. The Companies would prefer to wait and launch these programs once they have a better understanding of the local commercial market; currently the Companies are conducting such research. ICF believes that this is a reasonable strategy that is generally consistent with a conservative planning approach common for utilities that are running relatively new programs in immature markets. Such an approach helps mitigate risks to the Companies and their ratepayers, and helps ensure the long term success of the portfolio.

Table 4: Energy Consumption, Program Spending, and Program Costs, by Sector[4]

KU Customer Sector	Estimated Consump-tion, 2009 (GWh)		LG&E Customer Sector	Estimated Consump-tion, 2009 (GWh)		LG&E / KU Estimated Consump-tion, 2009 (GWh)		Sector	LG&E / KU Proposed Spending on DSM Programs ($M, Years 1-7)		LG&E / KU Avg Cost of Savings ($/kWh, Years 1-7)
Residential	6,353	53%	Residential	4,254	49%	10,607	51%	Residential	$218	86%	$0.21
General Service	1,835	15%	General Service	1,456	17%	3,291	16%	Commercial	$36	14%	$0 09
Large Power Service	3,910	32%	Large Commercial	2,980	34%	6,890	33%				
Total	12,098			8,690		20,788		Portfolio	$254		$0.18

Sources:
KU Elec - DSM RC Filing 12-08
LG&E Elec - DSM RC Filing 12-08
LG&E / KU Draft DSM Expansion Filing 1-11

4.3. Regulatory Treatment of Program Costs

The state of Kentucky's cost recovery mechanism is consistent with best practice, in that it includes program cost recovery and lost revenues recovery. However, the Companies must still prove that a DSM portfolio is cost-effective, which can be difficult when avoided costs are low. Similarly, customers' willingness to participate in energy efficiency program is lessened when retail rates are low, leading to longer payback periods. As demonstrated throughout this document, the Companies continue to offer cost-effective programs to each segment of the customer base. The Companies should continue to review best practice programs and look for new and innovative methods of program design and delivery that are still cost-effective.

In addition to a cost recovery mechanism, the establishment of mandatory savings or budget goals is another method that can ensure sufficient and stable funding for DSM programs. Some states, including Minnesota and Wisconsin, set a requirement that a certain percentage of sales or revenue determine the savings target or the total budget. Other states, including California and Vermont, use historical performance to set three-year budgets (which increase for each cycle) for DSM programs. Though Kentucky's utilities are not yet required to reach a savings or budget target, the governor's goal to offset at least 18 percent of the state's 2025 energy demand will necessitate consistent DSM investment and enable the Companies to set long-term DSM planning goals. The Companies should continue to work with the PSC to reach regulatory certainty and ensure their DSM investments will count toward any statewide or legislative goals.

4.4. Ratepayer Impact

ICF contends that the Companies' proposed DSM investment will have smaller impacts on customer bills than additional customer electricity use. This is illustrated by the Utility Cost Test (UCT) results for the Companies' portfolio, which are well above 1.00 (the overall ratio is 3.39). The UCT compares the costs of DSM programs incurred by the utility ("costs") against avoided costs of energy and demand ("benefits"). If the UCT Benefit-Cost (BC) ratio is greater than one, this means that the DSM program is less expensive than, and therefore a better deal to all ratepayers, than the generation alternative.

[4] Does not include the Industrial sector.

Some interveners, stakeholders, and utility commissioners contend that the Ratepayer Impact (RIM) test is the appropriate indicator of program cost-effectiveness when considering the impact of DSM investments on customers. If the RIM test BC ratio is less than 1.00, then it is likely that utility rates will increase in the short-term, either through a cost recovery factor or through a rate case, especially for non-participants. The RIM test's main advantage over other standard measures of DSM cost-effectiveness is that it is the only test that reflects revenue shifts. However, the RIM test also has serious disadvantages; as stated in the California Standard Practice Manual (CSPM):

> Results of the RIM test are probably less certain than those of other tests because the test sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.[5]

The other cost-effectiveness test ratios, including the Participant (PCT) test and the Total Resource Cost (TRC) test, show easily the benefits to program participants, and all ratepayers as a whole. The PCT test results for the portfolio are 8.24, showing that for each dollar that is spent on energy efficiency improvements, the participant will receive more than eight times as many benefits, through bill reductions and program incentives. Even when excluding the high PCT ratios from the existing programs, participants will still receive significant benefits from participating in the enhanced Residential and Commercial Conservation/Rebates programs.

The TRC test results for the portfolio are 3.01; this shows that for each dollar that is spent by both participants and utilities, they will receive about three times as many benefits through avoided energy costs. The TRC test (or a variation of it, the Societal Cost Test) is the primary cost-effectiveness test used in most jurisdictions, with the UCT commonly used as a secondary cost-effectiveness test.

Because the programs easily pass the TRC and UCT, and participants gain significant benefits from the programs, the Companies should continue to design and market the programs broadly, in order to increase participation and minimize the number of non-participants. The Companies should also monitor the RIM test and PCT BC ratios for cost-effectiveness; they should also use these test results with caution, and should not judge the value of individual programs using these tests exclusively.

Table 5: Benefit-Cost Ratios, by Cost-Effectiveness Test

Cost-Effectiveness Test	Benefit-Cost Ratio
TRC	3.01
UCT	3.39
RIM	0.82
PCT	8.24

[5] California Public Utilities Commission. California Standard Practice Manual for the Economic Analysis of Demand-Side Programs and Projects. October 2001. p. 15.

5. Program Reviews

The following enhanced existing, and new programs were reviewed and compared with comparable best practice programs:

The enhanced existing programs reviewed were:

- Residential Load Management Program
- Commercial Load Management Program
- Commercial Conservation/Commercial Incentives Program
- Residential Conservation/Home Energy Performance Program
- Residential Low Income Weatherization Program (WeCare)

New programs reviewed were:

- Smart Energy Profile
- Residential Incentives
- Refrigerator Removal Program

5.1. Expanded Programs

5.1.1. Residential Load Management

Description of the Companies' Program

The Companies' Load Management program utilizes one-way radio load control switches and thermostats to cycle off residential and small commercial customers' central air conditioner (CAC) and other systems during system peak times to reduce demand usage. The equipment is controlled (or cycled off) about 30 to 45 percent of each peak event. In exchange, participants who choose the switch option receive free installation of the equipment, and an annual bill credit. Participants who choose the thermostat option do not receive a bill credit incentive.

Under this program modification, the Companies are requesting the flexibility to increase the annual bill credit for CAC units for electric water heaters and pool pumps. To estimate cost-effectiveness, the Companies have proposed annual bill credit increases in Years 2 and 4; the actual increase will be determined in the future based on numerous factors. Participants who choose the thermostat option would continue to receive no annual incentive. The Companies are also proposing, beginning in Year 1, a one-time install bonus to new participants, increasing by $5 every two years. The Companies are proposing to increase the financial incentives to help increase participation compared to prior years, which has been less than half of the planned goals.

Components of Best Practice Programs

The following are components of best practice load control programs[6]:

- Multiple equipment options, such as one-way switches and two-way thermostats
- Multiple cycling options and durations
- Bill credits commensurate with reduction
- Targeting of high-use residential customers
- If applicable, incorporation of critical-peak pricing element or real-time pricing
- Monitoring of load impacts and use of interval data

Summary of Best Practice Programs

The We Energies Energy Partners program utilizes a one-way load control switch for residential customers' CAC systems. Participants can choose among three cycling options, with varying durations, with no limit to the number of events per year. The participant would receive either a $40 annual incentive for continuous cycling of four hours, or $50 for six hours, per day. The third option is a $12 annual incentive for 45 minutes cycling off and 15 minutes cycling on per hour, for up to eight hours per day. Participants can receive up to two switches per household; however, they would receive only one bill credit.

6 Adapted from http://www.peaklma.com/files/public/CustomerPrinciples.pdf.

We Energies has received approval to introduce new equipment and cycling options in order to expand the Energy Partners program by doubling the number of participants to 60,000 by 2012. The utility plans to introduce smart thermostats, in order to give participants additional control and allow them to override the utility signal. In addition, the utility plans to offer two new cycling options based on a 50 percent control strategy. Incentives for the three existing options will increase to between $50 and $80 per year. The utility also plans to target high-use residential users, in order to increase the demand reductions per participant.

The Energy Partners program expansion seeks to achieve greater participation goals through the adoption of best practice techniques. The use of a smart thermostat may attract new participants who otherwise would not have participated. In the future, the smart thermostat may also allow the utility to introduce real time pricing into the program. In addition, the introduction of new cycling options may also attract new participants, and give the utility more flexibility regarding demand reductions during events.

Southern California Edison's (SCE) Summer Discount Program (SDP) utilizes a one-way load control switch for residential and small commercial customers' CAC systems. For both residential and small commercial customers, SCE offers two cycling options and two incentive options, for a total of four program options. The cycling options consist of 50 percent and 100 percent; the two incentive options are Base and Enhanced. In the Base option, SCE is allowed to conduct a maximum of 15 load control events, with each event lasting up to six hours. In the Enhanced option, SCE is allowed to conduct an unlimited number of six-hour load control events. The participant would then choose one cycling option and one incentive option. Participants are eligible for up to $200 in bill credits per year.

The SDP incentives structure seems proportionate to the commitment required by the participant and the benefit to the utility, consistent with the best practice program components listed above. The SDP's incentives are more than three times higher for the 100 percent cycling option than for the 50 percent cycling option. Also, the Enhanced option incentives are twice as much as the Base option incentives. In addition, the incentive structure is based on system size, which rewards participants who achieve greater demand reductions. The varying incentive may also encourage the participation of high-use customers, who can then receive a bill credit that is among the highest in the country. Similarly, SCE incurs lower program costs by limiting incentive payments to participants whose system sizes are smaller than average.

Table 6: Residential Load Management Program Comparison

Program Element/ Metric	LG&E / KU	Best Practice Program: Less Mature Market We Energies, Energy Partners Program Start Year: 1992	Best Practice Program: More Mature Market Southern California Edison, Summer Discount Plan Program Start Year: 1985
Program Objective(s)	Reduce peak demand, and delay the need for new generation	Provide reliable and cost-effective demand response	Provide reliable and cost-effective demand response
Target Market(s)	Residential single family homes	Residential single family homes	Residential single family homes
Market Penetration (annual)	Currently at 19%, increasing to 25% by Year 3	Estimated at 3%	Estimated at 13%
Measures Types (continuing)	One way switches and thermostats for CAC and other appliances	One way switch for CAC	One way switch for CAC
Measures Types (new)	One way switches and thermostats for CAC and other appliances	Smart thermostat	One way switch for CAC
Incentive Structure	• $20 bill credit per customer per CAC unit, flexibility to increase to $40 in Year 4 • No bill credit for thermostat option • $8 bill credit per customer per electric water heater/pool pump, flexibility to increase to $16 in Year 4 • Proposed install bonus	Ranges from $20 to $80 per year, depending on cycling strategy, size of AC unit, and choice of number of events per season	Ranges from 5 to 18 cents per day per AC system size in tons, depending on cycling strategy, size of AC unit, and choice of number of events per season
Marketing	Traditional marketing efforts through direct mail, website, bill inserts, and other activities and events	Targeting of high-use customers, in addition to traditional marketing efforts through direct mail, website, bill inserts, and other activities and events	Traditional marketing efforts; Use of targeting to high-use customers is unknown
Delivery	LG&E / KU handles marketing, and monitoring of load impacts; Implementation contractor handles all other program activities, including equipment installation, maintenance, and repair, and auditing and verification	Through an implementation contractor, which handles all activities (marketing, equipment installation, maintenance, and repair, auditing and verification, data tracking, monitoring of load impacts), except the call center	SCE handles marketing, recruitment, and call center; Implementation contractor handles all other program activities

Discussion of the Companies' versus Others' Programs

Overall, the Companies' Load Management program compares favorably to best practice load control programs. Equipment costs correspond to what is available in the market, and program costs are comparable to best practice programs. In addition, the program contains features, such as the control of multiple customer appliances, which set it apart from other programs. A comparison of savings and cost-effectiveness is more difficult due to the disparity in retail rates, avoided costs, and system peak demand between the Companies and their peers. However, ICF concludes the Companies are expanding the program correctly by increasing incentives in order to increase participation and savings and decrease program costs.

Conclusions

ICF suggests the Companies consider the following implementation strategies in the future:

1. In addition to increasing the incentives, structure the incentives based on system size, in order to reduce payments to participants with smaller CAC systems. This could also encourage customers with larger system sizes to participate in the program.
2. Target high-use residential customers, similar to what We Energies is planning to do. This could decrease the program's marketing costs per participants, as well as identify customers for participation in other programs.
3. Introduce other best practice techniques, such as the introduction of real-time pricing. The availability of real-time pricing data to the participant would be akin to a price response program, and would allow for greater participant control during an event. The Companies would be able to increase participation by promoting multiple control options to participants.

Table 7: Residential Load Management Program Results Comparison

Program Element/ Metric	LG&E / KU		Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
	Year 1	Year 3	We Energies, Energy Partners 2009–2011	Southern California Edison, Summer Discount Plan 2009
Annual Energy Savings MWh	5,923	12,860	N/A	N/A
Annual Demand Reduction kW	145,000	172,000	39,000	639,800
Annual Incentive Costs	$2,260,700	$4,266,834	$3,000,000	N/A
Annual Non-Incentive Costs	$3,926,175	$5,734,218	$9,748,220	N/A
Annual Budget	$6,186,874	$10,001,052	$12,748,220	$59,106,954
Participants	131,000	157,000	30,000	343,107
kWh/Participant	45	82	N/A	N/A
kW/Participant	1.1	1.1	1.3	1.9
% Budget Incentive Costs	37%	43%	24%	N/A
% Budget Non-Incentive Costs*	63%	57%	76%	N/A
% Budget EM&V	18%	16%	2%	N/A
$/1st Year kWh	$1.04	$0.78	N/A	N/A
$/1st Year kW	$43	$58	$327	$92
Cost/Participant	$47	$64	$425	$172
NTG Ratio	*1.00*	*1.00*	*0.72*	*N/A*
**Includes % EM&V costs*		*Source(s):*	*We Energies filing, WI PSC website, Docket 05-UR-103*	*SCE filings, CA PUC website, Proceeding A0806001*

5.1.2. Commercial Load Management

Description of the Companies' Program

The Companies' Load Management program utilizes one-way radio load control switches and thermostats to cycle off residential and small commercial customers' central air conditioner (CAC) and other systems during system peak times in order to reduce demand usage. The equipment is controlled (or cycled off) about 30 to 45 percent of each peak event. In exchange, participants who choose the switch option receive free installation of the equipment, and an annual bill credit. Participants who choose the thermostat option do not receive a bill credit incentive.

Under this program modification, the Companies are requesting the flexibility to increase the annual bill credit for CAC units for electric water heaters and pool pumps. To estimate cost-effectiveness, the Companies have proposed annual bill credit increases in Years 2 and 4; the actual increase will be determined in the future based on numerous factors. Participants who choose the thermostat option would continue to receive no annual bill credit. The Companies are also proposing, beginning in Year 1, a one-time install bonus to new participants, increasing by $5 every two years. The Companies are proposing to increase the financial incentives in order to increase participation compared to prior years, which has been less than half of the planning goals.

Components of Best Practice Programs

The following are components of best practice load control programs[7]:

- Multiple equipment options, such as one-way switches and two-way thermostats
- Multiple cycling options and durations
- Bill credits commensurate with reduction
- Door-to-door recruitment of small commercial customers
- If applicable, incorporation of critical-peak pricing element or real-time pricing
- Monitoring of load impacts and use of interval data

Summary of Best Practice Programs

Both best practice comparison programs operate in the same market, California; however, the state's three investor-owned utilities (IOUs) and two largest municipal utilities have designed their direct load control programs differently. Pacific Gas & Electric (PG&E) has only been operating its current direct load control programs since 2007. PG&E's SmartAC program is targeted mostly to the residential sector (the share of small commercial customers is less than 1 percent) and is being co-marketed with SmartRate, a critical peak pricing tariff, using its recently installed smart meter technologies. Sacramento Municipal Utility District (SMUD) runs a best practice direct load control program that is open to residential customers only, while the Los Angeles Department of Water and Power (LADWP) does not run any direct load control programs.

[7] Adapted from http://www.peaklma.com/files/public/CustomerPrinciples.pdf.

San Diego Gas & Electric (SDG&E), which can be thought of as the less mature market, has only been operating its program since 2005. It has achieved a much larger share of small commercial customers due to its unique marketing approach. Southern California Edison (SCE), which can be thought of as the more mature market, has operated its program since 1985. The program has a high penetration rate in the residential sector, and a more modest penetration rate in the small commercial sector (though, with higher kW savings per participant). Although the Kentucky market has fewer system peak demand issues than California, there are some direct load control program design options that the Companies could incorporate into their programs.

SDG&E's Summer Saver program utilizes a one-way control switch for residential and small commercial customers' CAC systems. For small commercial customers, SDG&E offers two cycling options, 30 percent and 50 percent. The duration of each event is between two to four hours, with an annual maximum of 15 event days.

The Summer Saver program is SDG&E's entry into the load control market, and offers a simple design and incentive structure to small commercial customers. Since the program's initiation in 2005, it has recruited more than 5,000 small commercial participants for an estimated participation level of nearly 7 percent. SDG&E and its implementation contractor, Comverge, have undertaken traditional, as well as unique, marketing efforts, including door-to-door recruitment, and outreach to a variety of community groups. Although the number of programs that include small commercial customers is few, SDG&E has achieved a penetration rate that is higher than the direct load control programs for fellow California IOUs SCE and PG&E.

SCE's Summer Discount Program (SDP) utilizes a one-way load control switch for residential and small commercial customers' CAC systems. For small commercial customers, SCE offers three cycling options and two incentive options, for a total of six program options. The cycling options consist of 30 percent, 50 percent and 100 percent; the two incentive options are Base and Enhanced. In the Base option, SCE is allowed to conduct a maximum of 15 load control events, with each event lasting up to six hours. In the Enhanced option, SCE is allowed to conduct an unlimited number of six-hour load control events. The participant would then choose one cycling option and one incentive option. Participants are eligible for up to $200 in bill credits per year.

The SDP incentives structure seems proportionate to the commitment required by the participant and the benefit to the utility, consistent with the best practice program components listed above. The SDP's incentives are nearly three times higher for the 100 percent cycling option than for the 50 percent cycling option, which are in turn five times higher than the 30 percent cycling option. Also, the Enhanced option incentives are twice as much as the Base option incentives. The inclusion of the 30 percent cycling option, which is known as the "Maximum Comfort" option, can provide an entry for new and/or hesitant participants. In addition, the incentive structure is based on system size, which rewards participants who achieve greater demand reductions. The varying incentive may also encourage the participation of high-use customers (considering that the average reduction per participant is 11.4 kW), who can then receive a bill credit that is among the highest in the country. Similarly, SCE incurs lower program costs by limiting incentive payments to participants whose system sizes are smaller than average.

Table 8: Commercial Load Management Program Comparison

Program Element/ Metric	LG&E / KU	Best Practice Program: Less Mature Market SDG&E, Summer Saver Program Start Year: 2005	Best Practice Program: More Mature Market Southern California Edison, Summer Discount Plan Program Start Year: 1985
Program Objective	Reduce peak demand, and delay the need for new generation	Provide reliable and cost-effective demand response	Provide reliable and cost-effective demand response
Target Market(s)	Small commercial customers	Small commercial customers	Small commercial customers
Market Penetration (annual)	Currently at 5%, increasing to 6% in Year 3	Estimated at 7%	Estimated at 4%
Measures Types (continuing)	One way switches and thermostats for CAC and other appliances	One way switch for CAC	One way switch for CAC
Measures Types (new)	One way switches and thermostats for CAC and other appliances	One way switch for CAC	One way switch for CAC
Incentive Structure	• $20 bill credit per customer per CAC unit, flexibility to increase to $40 in Year 4 • Additional bill credit of $1 per ton per month for CAC units larger than 5 tons • No bill credit for thermostat option • $8 bill credit per customer per electric water heater/pool pump, flexibility to increase to $16 in Year 4 • Proposed install bonus	• Ranges from $9 to $15 per AC system size in tons, depending on cycling strategy, size of AC unit • Additional $10 Weekend Bonus Credit	Ranges from 1.4 to 40 cents per day per AC system size in tons, depending on cycling strategy, size of AC unit, and choice of number of events per season
Marketing	Traditional marketing efforts through direct mail, website, bill inserts, and other activities and events	Traditional marketing efforts, as well as door-to-door marketing and other direct outreach methods	Traditional marketing efforts; Use of targeting to high-use customers is unknown
Delivery	LG&E / KU handles marketing, and monitoring of load impacts; Implementation contractor handles all other program activities, including equipment installation, maintenance, and repair, and auditing and verification	Implementation contractor (Comverge) handles marketing and recruitment, and all other program activities	SCE handles marketing, recruitment, and call center; Implementation contractor handles all other program activities

Discussion of the Companies' versus Others' Programs

Overall, the Companies' Load Management program compares favorably to best practice load control programs. Equipment costs correspond to what is available in the market, and program costs are comparable to best practice. The most important feature is that the program is offered to commercial customers; most other load control programs are open only to residential customers. In addition, the program contains other features, such as the control of multiple customer appliances, which set it apart from other programs. A comparison of savings and cost-effectiveness is more difficult due to the disparity in retail rates, avoided costs, and system peak demand between the Companies and their peers. However, ICF concludes the Companies are expanding the program correctly by increasing incentives, in order to increase participation and savings, and decrease program costs.

Conclusions

ICF suggests the Companies consider the following implementation strategies in the future:

1. In addition to offering incentives based on system size, and increasing the annual incentives, the Companies should continue to monitor the incentive structures of comparable programs, and the relationship between incentives and new participants.
2. Recruit small commercial customers through unique marketing efforts, similar to what SDG&E does. In addition to increasing participation, this could decrease the program's marketing costs per participants, as well as identify customers for participation in other programs.
3. Introduce other best practice techniques, such as the introduction of real-time pricing. The availability of real-time pricing data to the participant would be akin to a price response program, and would allow for greater participant control during an event. The Companies would be able to increase participation by promoting multiple control options to participants.

Table 9: Commercial Load Management Program Results Comparison

			Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
Program Element/ Metric	LG&E / KU		We Energies, Energy Partners 2008	Southern California Edison, Summer Discount Plan 2009
	Year 1	Year 3		
Annual Energy Savings MWh	244	564	N/A	N/A
Annual Demand Reduction kW	5,800	7,500	12,132	127,100
Annual Incentive Costs	$81,724	$152,594	N/A	N/A
Annual Non-Incentive Costs	$240,096	$325,983	N/A	N/A
Annual Budget	$321,821	$478,578	$1,968,400	$14,776,739
Participants	5,100	6,300	5,403	11,167
kWh/Participant	48	90	N/A	N/A
kW/Participant	1.1	1.2	2.2	11.4
% Budget incentive costs	25%	32%	N/A	N/A
% Budget non-incentive costs*	75%	68%	N/A	N/A
% Budget EM&V	17%	15%	N/A	N/A
$/1st year kWh	$1.32	$0.85	N/A	N/A
$/1st year kW	$55	$64	$162	$116
Cost/Participant	$63	$76	$364	$1,323
NTG Ratio	1.00	1.00	N/A	N/A
*Includes % EM&V costs		Source(s):	*SDG&E filing, CA PUC website, Proceeding A0806002; Evaluations available at CALMAC.org*	*SCE filing, CA PUC website, Proceeding A0806001; Evaluations available at CALMAC.org*

5.1.3. Commercial Conservation / Commercial Incentives

Description of the Companies' program

The Companies' Commercial Conservation (Energy Audits)/Commercial Incentives program expands upon the current commercial audit program by providing additional incentives to commercial customers to make energy efficiency upgrades. In the current program, a customer receives a visit from a certified auditor, who then conducts a facility audit – either Level 1 for small commercial customers, or Level 2 or 3 for custom projects. The auditor then provides a report with recommendations for energy savings upgrades and the costs to install them. Customers can then choose to have the auditor install the upgrades, or can have another contractor implement the recommendations. Customers would receive the audit at no cost, but would have to pay for the upgrades themselves.

In the program expansion, the Companies seek to add refrigeration measures to the list of eligible projects, as well as offer incentives for custom measures. The Companies are also increasing the total amount of incentives available through the program by offering a set $100 per kW reduced incentive.

Components of Best Practice programs

The following are components of best practice load control programs:

- Inclusion of audits/assessments to educate customers and encourage participation
- Program design that includes both prescriptive and custom incentives for all measure types
- Applicability to and participation of all customer sub-sectors and sizes
- Use of trained contractors and trade allies, to market and implement the program
- Incorporation of EPA's Portfolio Manager benchmarking tool, in order to identify potential projects and monitor post-installation progress

Summary of Best Practice programs

The two programs discussed below can be considered best practice; however, the primary rationale to use them as comparison points is to detail the two models that are used most often for commercial and industrial (C&I) retrofit programs. Entergy Arkansas Inc. (EAI) has designed their C&I portfolio based on customer size, and developed custom incentives to encourage participation. On the other hand, NV Energy (comprised of Nevada Power and Sierra Pacific Power) uses a portfolio approach that segments each program based on measure type. The measure types are typically denoted as Prescriptive, Custom, and Retro-commissioning. A Prescriptive program generally includes a set incentive for a specific piece of equipment, such as $10 for a T8 lighting fixture. A Custom program typically sets an incentive according to kWh or kW saved in order to include equipment that is not covered by the Prescriptive program. Retro-commissioning programs include measures that are designed to improve building performance, and can include both prescriptive and custom incentives.

The Entergy Arkansas, Inc. (EAI) Quick Start portfolio was developed as a result of an Arkansas Public Service Commission order in 2007 for the state's investor-owned utilities to offer DSM programs to their customers. The Quick Start portfolio includes three energy efficiency programs that are targeted to commercial and industrial (C&I) customers, based on customer size and familiarity with energy efficiency upgrades.[8] The Small C&I program is available to customers with peak electricity demand of less than 100 kW. Customers can choose from a list of participating contractors, and receive a free walk-through assessment. The incentive amount is $115 per kW reduction for lighting, HVAC and chiller, and motors upgrades that are installed within 45 days. The Large C&I Energy Solutions is available to customers with peak electricity demand of 100 kW or greater. Customers are given more flexibility with regards to their energy assessment (i.e. they can choose their own contractor or have the program provide one). Similar to the Small C&I program, the incentive amount of $159 per kW reduction applies only to lighting, HVAC and chiller, and motors upgrades.

The Large C&I Standard Offer program is also available to customers with peak electricity demand of 100 kW or greater. This customer segment is assumed to be familiar with implementing energy efficiency upgrades and is given flexibility with regards to the participation process (i.e. they are not required to conduct an assessment). The process for this program is similar to other standard offer programs, where participant facilities are subject to pre- and post-installation inspections, and receive incentives based on the amount of peak demand reduced; for EAI's program, the incentive is $230 per kW reduction. For all three programs, incentives are paid by the utility following completion or verification of the project.

The advantage of this *Customer* approach is the simple design; customers are eligible for one program, and can receive incentives for the installation of upgrades for all end-uses and building types. If a customer has a peak demand of 50 kW, they know they are eligible only for the Small C&I program. They would then speak with an account representative, choose a contractor, and begin participation in the program. One disadvantage of the Customer approach is the lack of flexibility regarding program design. If, for example, because of the economic downturn, small commercial customers are not participating due to a lack of financing, the unused portion of the program budget is not easily transferable to the large customer programs. Another disadvantage is the preference given to measures that produce higher peak demand savings (HVAC, motors, etc.) versus those that produce lower peak demand savings (lighting, etc.). This would result in lost opportunities for certain energy efficiency retrofits that save energy but not demand.

NV Energy's Sure Bet Commercial Incentives program provides a variety of prescriptive and custom incentives, and technical assistance for non-residential customers across the utility's geographically-disparate Northern and Southern territories.[9] Customers submit one single pre-application form (required for large Prescriptive and all Custom projects), install the upgrades (using their preferred or an NV Energy-trained contractor), and receive incentive payments within 4-6 weeks of submitting post-installation project documentation. Through 2007, the program was utilizing 39 trained contractors.

The Prescriptive component of the program includes incentives for lighting, cooling (including HVAC units, variable speed drives for fans and pumps, and window film), miscellaneous (motor controllers

[8] More information is available at http://www.entergy-arkansas.com/energy_efficiency/business.aspx.

[9] More information is available at http://www.nvenergy.com/saveenergy/business/incentives/surebet/documents/applications/2009SureBetPP.pdf.

and pool/spa pumps), and commercial kitchen/refrigeration measures. The Custom component of the program provides incentives (for measures not covered by the Prescriptive component) of 10 cents per kWh for the first year's on-peak savings, and 5 cents per kWh for the first year's off-peak savings. The program also contains services for building optimization (similar to Retro-commissioning, as discussed above) and small commercial direct install incentives. Incentive payments to participants have a soft cap of $100,000; projects above this amount receive between 10% and 50% of the total incentive. In general, the incentives were designed to achieve a two year post-incentive payback. Program savings were nearly equal between Prescriptive and Custom projects, which show broad inclusion and participation among measure and customer types.

The advantage of this *Measure* approach is the flexibility with regards to program design. Customers are able to participate in multiple program components, while still receiving incentives for a variety of upgrades. A customer that needs both lighting upgrades and a chiller replacement would participate in both the Prescriptive and Custom components (while, at least in the Sure Bet case, submitting only one application). In addition, under this approach, programs would be unaffected by economic or other barriers that would restrict a customer segment from program participation. As explained above, in the "Customer" approach, if the Small C&I program is less popular than the Large C&I program, it would not be easy to transfer program funds from the Small C&I budget to the Large C&I budget. However, in the "Measure" approach, if lighting upgrades are less popular than HVAC upgrades within the Prescriptive component, additional funds could be used to market and install more HVAC upgrades. One disadvantage of the "Measure" approach is the additional infrastructure and costs needed to engage trade allies (manufacturers, retailers, etc.) for a Prescriptive component. In order to offer incentives for lighting and other upgrades, a utility would need to work with these trade allies to make sure their products are available in the market. However, over time, these costs should decline as the program expands.

Duke Energy Kentucky is following the *Measure* approach, and includes prescriptive incentives for lighting, motors, HVAC, refrigeration, and other measures as part of its SmartSaver program. The utility also offers an on-line benchmarking analysis. However, it does not offer any custom incentives, and incentive payments are typically capped at 50% of total project costs up to a maximum of $50,000 per customer facility. In the past few years, the number of installations has been heavily weighted towards lighting measures.

Table 10: Commercial Conservation / Commercial Incentives Program Comparison

Program Element/ Metric	LG&E / KU	Best Practice Program: Less Mature Market Entergy Arkansas C&I Programs Program Start Year: 2007	Best Practice Program: More Mature Market Nevada Energy Sure Bet Program Start Year: 1985
Program Objective(s)	Provide audits and rebates to qualifying commercial customers for the retrofit of less efficient equipment by adding refrigeration measures and a set per kW incentive to its existing program	Provide a suite of energy efficiency options to C&I customers, including audits, rebates, and custom incentives, including per kW	Provide prescriptive and custom energy efficiency incentives to C&I customers
Target Market(s)	Large commercial customers	All non-residential customers	All non-residential customers
Market Penetration (annual)	Estimated at 1%	Estimated at < 1%	Estimated at < 1%
Measures Types (continuing)	Facility audit, with recommendations for lighting, HVAC, and other measures	Facility energy assessments, with rebates for lighting, HVAC and chillers, and motors	Lighting, HVAC, refrigeration, and other prescriptive, as well as custom measures
Measures Types (new)	Facility audit, with incentives for lighting, HVAC, refrigeration, and custom measures	Facility energy assessments, with rebates for lighting, HVAC and chillers, and motors	Lighting, HVAC, refrigeration, and other prescriptive, as well as custom measures
Incentive Structure	$100 per kW reduced, up to an annual maximum of $50,000, or $100,000 over two years, per facility	Ranges from $115 to $230 per kW reduced	• Prescriptive – varies by measure • Custom – 5 to 10 cents per kWh reduced • Soft cap of $100,000 per participant
Marketing	Through the Business Service Center, the audit contractor, and trade allies, as well as through direct mail, newsletters, and targeting of large customers	• Small customers – through direct mail • Large customers – through Account Managers	Through the website and account executives, as well as direct outreach to CoC organizations, BOMA, etc.
Delivery	Current audit contractors will conduct audits, prepare reports with energy savings recommendations, install upgrades, or refer customers to Dealer Referral Network; Upgrades will then be installed by participating contractors	Depending on the program, both participating and non-participating contractors will conduct assessments and install upgrades	Implementation contractor (KEMA) handles all program activities, including applications, inspections and incentive processing

Discussion of the Companies' versus Others' Programs

The Companies' program is unique among the state's largest utilities, and it has historically exceeded their goals for number of audits performed, and achieved their goals for energy savings. The proposed expansion will address some of the issues detailed in the most recent evaluation report. For example, the $100 per kW incentive will likely increase the participation of large customers, whose peak demand reduction potential is greater than small customers. In addition, the inclusion of refrigeration measures will match the design of several best practice programs. Overall, the program's expansion to include additional prescriptive and custom measures makes it more similar to best practice programs in California, Nevada, Wisconsin, and other states.

Conclusions

ICF suggests the following in order for the program to reach its goals and continue program cost-effectiveness:

1. Per the most recent evaluation report, the Companies should ensure that the audits are comprehensive and are continuing to motivate customers to participate in the program. Many best practice programs also include audits and other technical assistance as a way to educate customers and market programs.
2. Monitor participation to ensure engagement with both small and large commercial customers. The incentive per kW will encourage participation from a broad mix of customers, and lead to cost-effective savings and achievement of program goals.
3. Continue to add prescriptive measures that are cost-effective, innovative, and available in the market. The Companies should also continue to work with trade allies to ensure their continued participation with and promotion of the program.
4. In the future, consider incorporating the EPA's Portfolio Manager benchmarking tool to provide customers with ongoing and post-project information regarding facility usage and savings. The tool is becoming an innovative program option in multiple utility portfolios, including California, Massachusetts, and Washington.[10] In addition, the Companies can use LG&E's experience with the *Louisville Kilowatt Crackdown* to introduce this to other parts of the territory. Since this initiative requires investment in equipment and personnel, the Companies should implement it once the expanded program has been running for a few years. This will allow the tool to be applied to a larger participant base, and ensure greater persistence of energy savings.

[10] More information is available at http://www.cee1.org/cee/mtg/06-09mtg/files/BB2Narel.pdf.

Table 11: Commercial Conservation / Commercial Incentives Program Results Comparison

Program Element/ Metric	LG&E / KU Year 1	LG&E / KU Year 3	Best Practice Program: Less Mature Market Entergy Arkansas C&I Programs 2008	Best Practice Program: More Mature Market Nevada Energy Sure Bet 2007
Annual Energy Savings MWh	54,988	54,988	31,834	84,532
Annual Demand Reduction kW	20,689	20,689	5,610	14,140
Annual Incentive Costs	$2,000,000	$2,000,000	$1,666,835	$3,579,927
Annual Non-Incentive Costs	$1,255,400	$1,316,121	$518,441	$2,796,550
Annual Budget	$3,255,400	$3,316,121	$2,185,276	$6,376,477
Participants	880	880	52	527
kWh/Participant	62,486	62,486	612,192	160,402
kW/Participant	23.5	23.5	107.9	26.8
% Budget incentive costs	61%	60%	76%	56%
% Budget non-incentive costs*	39%	40%	24%	44%
% Budget EM&V	1%	0%	N/A	N/A
$/1st year kWh	$0.06	$0.06	$0.07	$0.08
$/1st year kW	$157	$160	$390	$451
Cost/Participant	$3,699	$3,768	$42,025	$12,100
NTG Ratio	0.80 to 0.90	0.80 to 0.90	1.00	0.63
*Includes % EM&V costs		*Source(s):*	*EAI filing, Arkansas PSC website, Docket 07-085-TF*	*NV Energy filing, Nevada PUC, Docket 08-8011, 08-8012*

5.1.4. Residential Conservation / Home Energy Performance

Description of the Companies' program

The Companies' Residential Conservation/Home Energy Performance program expands upon the current audit program by providing additional incentives to single family customers to make energy efficiency retrofits for their homes. In the current program, a customer receives a visit from a certified auditor, who records appliance data and energy characteristics of the home. A blower door test was included in the audit in 2009. The auditor then prepares a report that includes historical energy usage, and provides a list of recommended energy upgrades and their related savings and costs. The customer would pay the $25 audit cost, and the full cost of any measure installations.

In the program expansion, customers choose from among three tiered participation options, corresponding to 10 percent, 20 percent, and 30 percent savings relative to total energy usage. Certified auditors conduct the Tier 1 audit (equivalent to the current level of service), and provide the participant with a list of Tier 2 and Tier 3 upgrades, and referrals to certified contractors. Participants can then choose to implement these upgrades at their own cost within 12 months of the initial audit, and submit post-installation rebate applications to the Companies. The rebate amounts are a maximum of $500 for Tier 2, and $1000 for Tier 3.

The current online audit would continue as part of the program. In addition to receiving the above report, online audit participants also receive a free four-pack of high efficiency light bulbs and are encouraged to participate in other components of the program to obtain additional savings.

Components of Best Practice programs

The following are components of best practice residential retrofit programs:

- Tiered efficiency options, ranging from walk-though audits to comprehensive audits (diagnostic audits that include blower-door and duct blaster tests), as well as a range of home efficiency project options
- Incentive options (with cost cap) commensurate with efficiency options, including audit with direct install to rebates
- Focus on whole-home approach
- Use of certified (e.g. RESNET or BPI) contractors, to market and implement the program
- Coordinate with statewide agencies, if applicable

Summary of Best Practice programs

The Baltimore Gas and Electric (BG&E) Smart Energy Savers portfolio includes an audit component, a Quick Home Energy Check-up, and a Home Performance with ENERGY STAR® (HPwES) component, for residential single-family customers. Customers who choose the quick audit receive a visit from a certified auditor, and can have the $40 audit fee waived by installing at least three out of five measures from a list that includes CFLs and hot water measures. The auditor also checks the insulation and air sealing levels, and the HVAC systems, and provides a list of findings and recommendations that can further reduce the participant's energy usage and costs.

Participants can also choose to receive a more comprehensive and diagnostic audit through HPwES. A BPI-certified contractor would conduct an HPwES Home Energy Audit, including blower door and duct blaster tests, and present a list of efficiency upgrade opportunities to the participant. The upgrades include air and duct sealing, insulation, and HVAC and hot water systems. The contractor would then install the agreed-upon upgrades, and receive full payment for services from the participant. After about six to eight weeks, the participant would receive partial reimbursement via the rebate check. Rebates are limited to $1300 per participant, but can exceed this amount if a new HVAC unit is installed.

The HPwES program began in Maryland in 2007 as a pilot program run by the Maryland Energy Administration (MEA). MEA's program was a success, and received an EPA Excellence in ENERGY STAR Promotion Award in 2009. Using the successful pilot as a model, BG&E's HPwES program design was submitted for and received regulatory approval in the fourth quarter of 2008, and was approved by the EPA as a Program Sponsor in the second quarter of 2009. Sponsors are able to market their programs using the nationally-known ENERGY STAR brand name, and take advantage of other support, including marketing toolkits and sales and contractor training courses. The program began operating in the third quarter of 2009 as the state's first utility-run HPwES program, and includes 25 qualified contractors.

With the use of multiple installation contractors, BG&E's program follows the HPwES market transformation model. This approach typically can take up to one year or more to ramp-up, in order to build program infrastructure, and can be more expensive in the short term than the resource acquisition model. However, in the long term, awareness of the program and its contractor network could result in lower costs and greater energy savings. BG&E's tiered approach, beginning with the Quick Home Energy Check-up, is designed to mitigate the long lead time, and provide customers with simply-designed retrofit options.

Massachusetts' MassSAVE portfolio is a public/private partnership that provides energy efficiency options to customers through their local utility. MassSAVE has contained an HPwES component since 2002, is also an HPwES Program Sponsor, and has been recognized as Best Practice by The American Council for an Energy-Efficient Economy (ACEEE). National Grid's HPwES program contains a no-cost home energy assessment (HEA) and offers rebates for efficiency upgrades. The HEA is conducted by the implementation contractor's (Conservation Services Group) certified auditors, and includes blower door and duct leakage tests. The contractor then installs the agreed-upon upgrades, and coordinates with sub-contractors for additional upgrades as necessary. Typical upgrades include air sealing, insulation, and the installation of efficient HVAC systems. Rebates are available for up to 75 percent of installation costs, with a $2000 maximum. Participants are also eligible for zero-interest financing of up to $15,000 over seven years, through MassSave's HEAT Loan program.

National Grid's retrofit program has been conducting HEAs since 1980, but the program's original focus was on education. Since the advent of the HPwES model in 2001, the program has evolved into a whole-home approach. National Grid's HPwES program follows the resource acquisition model, where typically one contractor implements the program, and installs the efficiency upgrades. This results in lower marketing and training costs, and allows the utility and the contractor to bring the program to the market more quickly. In addition, the resource acquisition model can result in more participants and installations, greater energy savings per home, and market penetration rates compared to the market transformation model.

Table 12: Residential Conservation / Home Energy Performance Program Comparison

Program Element/ Metric	LG&E/ KU	Best Practice Program: Less Mature Market BGE, Retrofit Program Start Year: 2009	Best Practice Program: More Mature Market National Grid, MassSAVE Program Start Year: 2000
Program Objective(s)	Utilize a whole-house approach to provide single family homes with additional options for energy saving retrofits and continue the participation from current audit programs	Two-tiered approach to motivate residential single family homes to adopt comprehensive, whole-home energy retrofits	Provide a singular source for home retrofit measures through audits, incentives, and education
Target Market(s)	Residential single family homes	Residential single family homes	Residential single family homes
Market Penetration (annual)	• 0.2% in Year 1, increasing to 0.3% in Year 3 • On-line audit penetration of 0.4% (3,000 audits) in Year 1, increasing to 0.8% (6,000 audits) in Year 3	Estimated at 0.04%; Increasing to 0.2% in 2010	Estimated at 0.6%
Measures Types (continuing)	• On-line audit - 4-pack high efficiency light bulbs; On-site audit consisting of visual inspection, appliance data recording, and other home measurements • Also includes a blower door test	• Tier 1 - Quick Home Energy Check-up • Tier 2 - Home Performance with ENERGY STAR	• Tier 1 - Information only • Tier 2 - Audit, and installation of insulation, air sealing measures, programmable thermostats
Measures Types (new)	• On-line audit - 4-pack high efficiency light bulbs; Tier 1 - Similar to on-site audit, and includes CFLs, hot water and minor air sealing direct install measures • Tiers 2 and 3 - Other air sealing, insulation, and HVAC maintenance measures	• Tier 1 - Quick Home Energy Check-up • Tier 2 - Home Performance with ENERGY STAR	• Tier 1 - Information only • Tier 2 - Audit, and installation of insulation, air sealing measures, programmable thermostats
Incentive Structure	• Tier 1 - Direct install measures (corresponds to 10% savings) • Tier 2 - Post installation $500 rebate (20% savings); Tier 3 - Post-installation $1000 rebate, (30% savings)	• Tier 1 - Audit with CFL and hot water kit • Tier 2 - Prescriptive incentives with 15% measure cost cap	75% of measure costs up to $2000

		Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
Program Element/ Metric	LG&E / KU	BGE, Retrofit Program Start Year: 2009	National Grid, MassSAVE Program Start Year: 2000
Marketing	• Traditional marketing efforts through direct mail, website, bill inserts, and other activities and events • Prior program has had most success with bill inserts/direct mail	Traditional marketing efforts, as well as through contractor outreach	Through MassSave brand awareness campaign, which includes media buys and direct mail, and through implementation contractor
Delivery	Through Dealer Referral Network, consisting of certified contractors	Through implementation contractor, and technical sub-contractors, many of whom are HERS raters and/or BPI Building Analysts	Through primary implementation contractor, and sub-contractors

Discussion of the Companies' versus Others' Programs

Overall, the Companies' Residential Conservation / Home Energy Performance program compares favorably to best practice home retrofit programs. The program's expansion to include multiple audit and rebate options and focus on a whole-home approach makes it similar to best practice programs in Maryland, Massachusetts, New York, Wisconsin, and other states. In addition, the Companies can take advantage of their existing relationship with the BPI network to expand program infrastructure. However, since the program is not run statewide, as is the case in other states, the Companies are at a disadvantage in that they are not able to share marketing, contractor training, and other costs.

Conclusions

ICF suggests the following in order to overcome this and continue program cost-effectiveness:

1. Investigate the option of becoming an HPwES Program Sponsor. Based on conversations with the Companies, ICF believes they have already begun researching the advantages and disadvantages of sponsorship.
2. While considering HPwES resource acquisition model and the market transformation model, also consider a hybrid approach, where the resource acquisition model eventually evolves into the market transformation model.
3. If using the market transformation model, build the program infrastructure and contractor network such that, over time, minimal involvement by the Companies will be necessary. The availability of more contractors will increase competition, decrease customers' costs, and decrease the Companies' program costs.
4. In lieu of statewide resources, take advantage of EPA national program support and expertise from utilities in other states.

Table 13: Residential Conservation/Home Energy Performance Program Results Comparison

Program Element/ Metric	LG&E / KU		Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
	Year 1	Year 3	BGE, Retrofit 2009	National Grid, MassSAVE 2007
Annual Energy Savings MWh	2,948	5,165	642	4,839
Annual Demand Reduction kW	767	1,313	190	1,169
Annual Incentive Costs	$180,000	$300,000	N/A	N/A
Annual Non-Incentive Costs	$1,280,826	$1,907,217	N/A	N/A
Annual Budget	$1,460,826	$2,207,217	$1,361,268	$5,378,468
Participants	7,200	14,000	1,716	6,000
kWh/Participant	409	369	374	807
kW/Participant	0.1	0.1	0.1	0.2
% Budget incentive costs	12%	14%	N/A	N/A
% Budget non-incentive costs*	88%	86%	N/A	N/A
% Budget EM&V	0%	0%	0%	3%
$/1st year kWh	$0.50	$0.43	$2.12	$1.11
$/1st year kW	$1,905	$1,681	$7,165	$4,601
Cost/Participant	$203	$158	$793	$896
NTG Ratio	1.00	1.00	0.90	N/A
**Includes % EM&V costs*		*Source(s):*	*BGE filing, MD PSC, Case 9154*	*National Grid filing, MA DOER website; ACEEE Compendium of Champions report, 2008*

5.1.5. Residential Low Income Weatherization (WeCare)

Description of the Companies' program

The Residential Low Income Weatherization Program (WeCare) is designed to reduce energy consumption for LG&E and KU's low income customers. The program provides energy audits, energy education, performs blower door tests, and installs weatherization and other energy conservation measures on qualified houses. The modified WeCare program presented in this filing is the third generation of the Companies' Low Income weatherization initiative. The original Energy Partners Program (EPP) pilot (1994) was modified to increase cost-effective savings based on EM&V findings; the program evolved into the WeCare Low Income Weatherization Program in 2001. The third generation program (also called WeCare) builds upon the Companies' experience with this hard-to-reach sector by adding HVAC unit replacement and envelope sealing measures to their list of offerings. The Companies are proposing this expansion in WeCare's offerings because the program has found that for a portion of eligible customers, there is a significant need for, and significant savings potential associated with installing a new HVAC unit and/or envelope sealing. In addition, the Companies are committed to the expansion of the program by more than tripling the budget and number of participants between Year 1 and Year 7 of program operation.

Components of Best Practice programs

Low income weatherization programs have been implemented by both public and private organizations for decades. Therefore, there is a wealth of literature on best practices.

Best practices in the delivery of low income weatherization program include:

- Leveraging efforts of other programs, e.g. local LIHEAP and WAP programs;
- Making the program stable and consistent;
- Setting clear expectations with auditors/contractors;
- Auditing a statistically significant sample of weatherized homes;
- Developing a network of local auditors and installers who are committed to high-quality standards;
- Controlling for free-ridership through periodic market studies, and consumer surveys; and,
- Offering a mix of services and measures attractive to homeowners.[11]

Summary of Best Practice programs

It is standard practice in the U.S. that DSM portfolios include at least one program that provides energy efficiency services to low income customers. Even though these programs are typically less cost-effective (have lower TRC and UCT test results) than other programs, most utility commissions make exceptions to their cost-effectiveness rules under certain circumstances. In the case of low income programs, commissions also consider fairness criteria in order to ensure that DSM services are made available to each market segment. Further, most commissions also

[11] Many of these best practices were drawn from Best Practice Benchmarking for Energy Efficiency Programs: Residential Single-Family Comprehensive Weatherization Best Practices Report. Available at, http://www.eebestpractices.com/pdf/BPSummaryTable_R4.PDF.

require the DSM portfolio as a whole to be cost-effective so that more expensive low-income, education and pilot initiatives are offset by other programs that are less expensive such that the end result is a portfolio of DSM programs that passes the TRC and/or the UCT test(s).

ICF chose three programs against which to compare WeCare. These programs are operated in states with different levels of market maturity; California (most mature), Colorado (somewhat mature), and Texas (less mature).

The PG&E, Xcel (Public Service), and AEP-Texas North (TNC) low-income weatherization programs have many common elements, including:

- Comprehensive audit and weatherization services;
- Customer education;
- Coordination with local LIHEAP of WAP programs; and,
- Reliance on weatherization contractors to deliver program services.

Based on our understanding of these utilities' low income initiatives, each program conducts all of the seven best practices listed above.[12]

The main differences between these programs are the extent of their coordination with other low income programs and the range and extent of program marketing. Xcel's program, for example, is heavily leveraged by state and federal low income programs; in fact, the program was designed to complement the services of, and acquire additional savings beyond those achieved by public programs. PG&E promotes their program heavily in communities throughout its large service territory. Program representatives travel to community forums and conduct presentations on the utility's low income energy efficiency offerings and the "CARE" tariff (mandated by the CPUC), which is available to qualified low income customers. TNC's program is a requirement set forth by the State Senate to provide weatherization services and efficiency education to low income customers. Participating agencies verify customer eligibility, audit homes, and determine which measures to install based on savings-to-investment ratios (SIRs). home, and market penetration rates compared to the market transformation model.

[12] One exception noted by ICF is that it is not clear how often and at what level of detail the Xcel and TNC programs are evaluated.

Table 14: Residential Low Income Weatherization (WeCare) Program Comparison

		Best Practice Program: Market Maturity High	Best Practice Program: Market Maturity Mid	Best Practice Program: Market Maturity Mid-to-Low
Program Element/ Metric	LG&E / KU	PG&E, Energy Partners Program Program Start Year: 1983	Xcel Energy Colorado, Single Family Low-Income Weatherization Program Program Start Year: NA	AEP North Texas (TNC), Targeted Low-Income Program Start Year: NA
Program objective(s)	(1) Reduce customer energy consumption and expenditures, and arrearages (2) Provide program participation opportunities for hard-to-reach markets	Increase low income customer comfort while reducing their energy consumption, costs and economic hardship.	Provide no-cost energy efficiency services to income-eligible customers, seniors and disabled. Increase and expand education among low income customers on the importance of energy efficiency and the value of taking action to improve efficiency in their homes.	Cost-effectively reduce the energy consumption and energy costs of TNC's low income residential customers.This program is required per TX State Senate Bill 712 "Weatherization Program"
Target Market(s)	Households at or below LIHEAP Federal Poverty level. Both homeowner and renters are eligible. There are 3 Tiers of participants: A, B, and C. Customers in Tier A have the lowest energy use and those in Tier C have the highest. The higher use clients (Tiers B and C) are initially identified by their annual gas or electric consumption. These clients usually receive multiple visits from the Weatherization Audit Contractor.	Low income households as defined by the CA Public Utilities Commission (CPUC). 2006 threshold was household income less than or equal to 200% of poverty level.	Households with median income below 80% of area median income. Participants must first apply for LIHEAP funding. Customers meeting DOE WAP funding guidelines are also automatically considered eligible	To be eligible, customers must meet current DOE Weatherization Assistance Program (WAP) income eligibility guidelines (200% of poverty level in 2009), receive electric power from TNC, and have electric air conditioning.
Market penetration (annual)	1,200 homes/year, increasing to 4,200 homes/year in Year 7	66,000 homes (approximately 2% of qualified homes)	1,958 single family homes	39 homes

Program Element/ Metric	LG&E / KU	Best Practice Program: Market Maturity High PG&E, Energy Partners Program Program Start Year: 1983	Best Practice Program: Market Maturity Mid Xcel Energy Colorado, Single Family Low-Income Weatherization Program Program Start Year: NA	Best Practice Program: Market Maturity Mid-to-Low AEP North Texas (TNC), Targeted Low-Income Program Start Year: NA
Measure types (continuing)	Weatherization, appliances, HVAC repair, hot water, CFLs	Weatherization, appliances, HVAC repair, hot water, CFLs	Services can include an energy audit, attic, wall and crawlspace insulation, air leakage reduction, appliance safety inspections, forced air efficiency assessment, high efficiency lighting surveys and other safety inspections.	Weatherization, other cost-effective measures.
Measures types (new)	HVAC (replacement) and envelope repair	NA	NA	NA
Incentive structure	All program services and measures are free to participants. Measure caps vary by customer Tier.	All program services and measures are free to participants.	All program services and measures are free to participants.	Measures are installed based on measure savings-to-investment (SIR) ratio. Installed measures are free to participants.
Marketing	The Weatherization Audit Contractors (WACs) are the primary marketing arm of the program, conducting direct marketing through mail and telephone solicitation. The primary source of participants is a targeted list prepared by LG&E / KU. Secondary sources of clients include, LIHEAP clients, referrals from local WAP programs, and referrals by local community-based organizations.	The program is promoted primarily through auditors/contractors, but PG&E also conducts extensive community outreach, in addition to traditional marketing collateral telemarketing, and promotion through the program Web site. Participation in community events has been extensive. Presentations promote both the weatherization services as well as the state's special billing rate for low income populations.	The program is promoted through local low income service providers. The program Web site directs interested customers to appropriate agencies. Xcel customers are informed of the program when they sign up for LIHEAP funding.	The program conducts targeted outreach to weatherization service providers in TNC's territory.

		Best Practice Program: Market Maturity High	Best Practice Program: Market Maturity Mid	Best Practice Program: Market Maturity Mid-to-Low
Program Element/ Metric	LG&E / KU	PG&E, Energy Partners Program Program Start Year: 1983	Xcel Energy Colorado, Single Family Low-Income Weatherization Program Program Start Year: NA	AEP North Texas (TNC), Targeted Low-Income Program Start Year: NA
Delivery	The program is delivered primarily by the WACs. All participants (Tiers) receive an initial visit during which the WAC performs a walk through audit and installs low-cost measures. WACs recommend additional measures and the program pays for any recommended projects implemented, up to the cap for the customer's Tier. For all projects completed, the auditor conducts a post-installation inspection and education session.	All participants receive a comprehensive energy analysis of their home. Customers are asked to commit to at least 3 energy conservation practices. CFLs are directly installed. Participants are eligible installation qualified measures recommended by the auditor.	During the weatherization process auditors provide participants with education materials historical energy use data, and a billing analysis.	Weatherization service providers verify customer eligibility, conduct an assessment of eligible customer homes, and install cost-effective measures.
Leveraging of Federal funds for low income weatherization	WeCare coordinates with the local Weatherization Assistance Program (WAP). Coordination efforts are focused on Tier A WeCare customers who are eligible for fewer WeCare incentives than Tier B and C customers.	Program coordinates with local LIHEAP and WAP programs, as well as other low income programs run by state agencies.	Xcel's program complements federal weatherization (WAP) grants to produce incremental, cost-effective energy savings, and develops annual contracts wit the eight weatherization agencies within their territory.	The program coordinates with the local WAP program.

Discussion of the Companies' versus Others' Programs

ICF finds that the Companies' WeCare program is consistent with best practice in low income weatherization program design. Amongst others, best practices exhibited by WeCare include (1) Leveraging federal funds for Weatherization; and, (2) Offering a mix of services and measures attractive to homeowners. This is very challenging market in which to achieve cost-effective savings, but the Companies have learned from their experience and adapted the program to changing market conditions, making WeCare more cost-effective than most comparable programs around the country.

The differences in program delivery between WeCare and the other programs primarily reflects state rules about low-income programs, or are implementation strategies found to be effective in those particular territories. For example, WeCare's tiered approach to low-income program services helps the Companies maximize program cost-effectiveness.

The Companies' tiered approach to program delivery helps ensure that low income program dollars are spent cost-effectively by spending more on homes that are the most energy-intensive (Tier C, customers using more than 16,000 kWh). This does not preclude other low income customers from receiving program services. Tier A (customers who use up to 11,499 kWh annually) and Tier B (customers who use between 11,500 and 16,000 kWh annually) customers are also eligible to receive a comprehensive audit, education and free measures (spending caps are lower for Tier A and B customers).

WeCare also compares favorably against other programs in terms of spending levels. Most low income program cost at least $1 per first year kWh, but the Companies have managed to keep overhead low, maintain high quality services, and deliver results. Although Xcel's program is less expensive, this largely reflects the explicit role of Xcel's low income programs within the state of Colorado – its program is heavily leveraged by federal and state funds.

Approximately 9 percent of the Companies' proposed portfolio budget is dedicated to low-income customers for weatherization and related services; this amount increases to nearly 20 percent in Year 7. ICF finds that the Companies' initial level of spending on low income energy efficiency services is reasonable and appropriate, given the maturity of the market in the Companies' territory, given the levels of federal spending and program activity (WAP and LIHEAP) in Kentucky, and balanced against the Companies' need to meet the governor's aggressive energy savings goals.[13]

ICF also commends the Companies for increasing the program's participation and budget goals each year of program implementation. Since the State of Kentucky received an influx of WAP dollars through the federal Stimulus bill, ICF recommends that the Companies continue coordination efforts with local WAP and LIHEAP programs so that ratepayer dollars dedicated to the Companies' low-income initiatives are not wasted on supplemental program services. In addition, ICF recommends that the Companies monitor and evaluate the program to ensure that spending is efficient, and is generating consistent impacts over time.

[13] As stated in "Intelligent Choices for Kentucky's Energy Future", the goals are to reduce energy consumption in Kentucky by at least 18 percent below currently projected 2025 energy consumption.

Conclusions

Based on a review of the proposed WeCare modification in this filing, and the existing WeCare program implementation manual, ICF concludes that WeCare implements the following best practices:

1. Leveraging efforts of other programs, e.g. local LIHEAP and WAP programs. WeCare coordinates with these programs intelligently by leveraging federal dollars where is the Companies are spending less – on Tier A customers. ICF hopes that the Companies continue to carefully coordinate with local WAP and LIHEAP programs to ensure that WeCare's services complement those provided by the federal programs as these public programs grow through funds provided by the Stimulus package.
2. Making the program stable and consistent. WeCare's core program services have remained stable over time. Changes and new offerings were/are being made consistent with EM&V results and market demand.
3. Auditing a statistically significant sample of weatherized homes. WeCare conducts a technical process review (TPR) of each project. TPRs take place on 100 percent of participant jobs within one week of the field work.
4. Offer a mix of services and measures attractive to homeowners. The Companies continue to add and change program offerings over time to capitalize on existing market conditions and demand. Adding HVAC replacement measures further diversifies the Companies' measure mix available to low-income customers.

Table 15: Residential Low Income Weatherization (WeCare) Program Results Comparison

			Best Practice Program: Market Maturity High	Best Practice Program: Market Maturity Mid	Best Practice Program: Market Maturity Mid-to-Low
Program Element/ Metric	LG&E / KU Year 1	LG&E / KU Year 3	PG&E, Energy Partners Program 2006	Xcel Energy Colorado Single Family Low-Income Weatherization Program 2009 (from DSM Plan0	AEP North Texas (TNC) Targeted Low-Income 2008
Annual Energy Savings MWh	2,632	4,825	24,300	1,983	95
Annual Demand Reduction kW	262	481	NA	175	31
Annual Incentive Costs	$0	$0	NA	$666,421	$131,300
Annual Non-Incentive Costs	$2,368,462	$3,956,847	NA	$83,049	$21,700
Annual Budget	$2,368,462	$3,956,847	$90,000,000	$749,470	$153,000
Participants	1,200	2,200	66,000	1,958	39
kWh/Participant	2,193	2,193	368	1,013	2,436
kW/Participant	0.2	0.2	NA	0.1	0.8
% Budget incentive costs	0%	0%	NA	89%	86%
% Budget non-incentive costs*	100%	100%	NA	11%	14%
% Budget EM&V	5%	3%	NA	2%	NA
% Portfolio budget dedicated to low income weatherization services	9%	11% (increases to 20% in Year 7)	California PUC rules treat low income programs separately from resource, or "impact" programs. The Low Income Energy Efficiency (LIEE) programs have their own portfolio and cost-effectiveness standards.	4%	15%
$/1st year kWh	$0.90	$0.82	$3.71	$0.38	$1.38
$/1st year kW	$9,033	$8,231	NA	$4,278	$4,935
Cost/Participant	$1,974	$1,799	$1,364	$378	$3,923
NTG Ratio	1.00	1.00	1.00	0.96	1.00
**Includes % EM&V costs*		*Source(s):*	*ACEEE. 2008 Compendium of Champions*	*Xcel Energy. 2009/2010 DSM Biennial Plan. Docket No 08A-366EG. Public Service Commission of Colorado. February 2009.*	*AEP North Texas (TNC). 2009 Energy Efficiency Plan and Report. April 1, 2009.*

5.2. New Programs

5.2.1. Smart Energy Profile

Description of the Companies' program

The Smart Energy Profile (SEP) program is unique amongst energy report-type initiatives in its foundations in social marketing research, and its built-in experimental design. The program will select large samples of test and control customers and directly mail the report to the test group on a monthly basis. Savings will be estimated through an econometric analysis comparing energy use between the test and control group. The program will specifically target high-use customers, at least in initial program years.

The Companies will use existing customer data, such as service point information, account information and current energy consumption to develop targeted, customer Smart Energy Profiles that will be mailed to customers at regular intervals throughout the year (e.g. monthly). Elements that are presented in the report may include a comparison of the customer's energy use vis-à-vis their peers (residents with similar home/building characteristics), presentation of the customer's current energy use versus their historical use, as well as customized and targeted messages to help the customer reduce energy use. The report will promote and recommend program and efficiency measures likely to benefit the customer based on individual household energy usage patterns.

Components of Best Practice programs

There are not any established best practices for social marketing-type programs, as these represent a relatively new type (or at least, less-evaluated) form of DSM initiative. Based on ICF's professional judgment and experience implementing DSM programs nationwide, we believe the following activities comprise best practices in the delivery of a Smart Energy Profile program:

- A clear and careful experimental design. Precise measurement of program savings requires early coordination with an EM&V contractor to ensure that the test and control groups are properly selected.
- Longitudinal data collection. Evaluations can demonstrate that first year program savings are significant and very cost-effective. However, savings persistence is not as well understood. For the program to learn and improve over time, both test and control group energy use data should be tracked and evaluated once customers have stopped receiving the report.
- Identify and target high-use customers. Research has shown the biggest energy reduction comes from this group.
- Deliver information in the reports in a manner than minimizes the boomerang effect. Often, customers that find out their energy use is less than their peers can subsequently increase their energy use. Some programs have found that the means of delivering information about peer energy use can minimize this effect.[14]

[14] Hunt Alcott. Social Norms and Energy Conservation. Departments of Economics and Sloan School of Management, Massachusetts Institute of Technology (MIT). October 2009.

Summary of Best Practice programs

These programs are not necessarily *best practice*, for reasons discussed above. Rather, they represent two distinct approaches to Smart Energy Profiles implemented by program administrators.

Connexus Energy in central Minnesota began implementing its HER program in 2008. Connexus' program provides a monthly report to a large group of residential customers; the report contains two modules (1) The Social Comparison Module, which compares household electricity consumption over the past twelve months to the mean of its comparison group in the twentieth percentile, and (2) The Action Steps Module, which includes energy conservation tips (behavioral) and retrofit measures offered through Connexus' other programs. A recent evaluation of Connexus' HER program, which compared changes in household energy use in the test group to that of the control group (who did not receive the report) showed annual electricity savings of approximately two percent in the test group (those receiving the report for a year).

Duke Energy Kentucky's Personalized Energy Report (PER) pilot program also delivers customized home energy use information to residential customers. The PER program is provided to qualified residential customers who complete a basic home energy survey, either on-line or mailed-in. The PER is then produced on-line, or mailed to participants, depending on the customer's preference. The PER the report evaluates energy usage in the entire home and provides recommendations, many of which are very low cost, to the consumer who may later undertake some of these actions. Participants also receive six free CFLs.

Connexus' program design and costs are very similar to the Companies' proposed SEP program, as shown in Tables 15 and 16. Note that while the data shows higher first year market penetration for Connexus' program, they are also a much smaller utility than the Companies, totaling 96,000 residential customers. Because of the similarity in program design, we would expect the Companies' program to perform similarly to Connexus', as well to a similar pilot run by the Sacramento Municipal Utility District (SMUD), which also resulted in evaluated annual energy savings of approximately two percent in for the test group receiving the Smart Energy Profile.[15]

Based purely on program design, ICF believes that the Companies' proposed energy report program is superior to Duke's PER pilot. The SEP program will have significant market penetration, which will be challenging for the PER pilot to achieve since participants enroll voluntarily.[16] The SEP program also contains a social marketing component (comparing peer energy use), which research shows has been very effective at reducing customer energy use. Further, the SEP program has a built-in experimental design that helps ensure precise measurement of participant savings.

[15] Summit Blue Consulting. Impact Evaluation of Positive Energy SMUD Pilot. May 2009.

[16] Note that programs similar in design to the Companies' have shown very low opt-out rates (less than one percent).

Table 16: Smart Energy Profile Program Comparison

Program Element/ Metric	LG&E / KU	Best Practice Program: Less Mature Market Connexus Energy (Central Minnesota), Home Energy Report Program Start Year: 2008	Best Practice Program: More Mature Market Duke Energy Kentucky, Personalized Energy Report (PER) Program Start Year: FY2009
Program Objective(s)	The objective of this program will be to educate customers about their energy consumption, encourage them to reduce consumption and empower them with tools, techniques and technology to use energy more wisely.	The objective of this program is to reduce customer home energy use through targeted, customized residential energy use education and marketing.	This program was designed to overcome market barriers amongst residential customers such as lack of consumer education and knowledge of specific ideas for reducing energy usage. The customized energy report is designed to help customers better manage their energy costs.
Target Market(s)	Residential. High energy users.	Residential. Those receiving the report must have one full year of electricity bill history as of the program start.	Residential single family customers who have not received measures through Duke's Home Energy House Call or Residential Conservation & Energy Education programs within the last three years.
Market penetration	14% after Year 1, 50% after Year 3	41%	NA
Measures	There are no specific measures offered by this program beyond the provision of the home energy report. The report will recommend measures available through other LG&E / KU programs based on the customer's energy use profile.	There are no specific measures offered by this program beyond the provision of the home energy report. The report will recommend measures available through other utility programs based on the customer's energy use profile.	In addition to the home energy report, participating customers will also receive 6 free CFLs.
Incentive structure	There are no specific incentives offered by this program beyond the provision of the home energy report. The report will recommend incentives available through other LG&E / KU programs based on the customer's energy use profile.	There are no specific incentives offered by this program beyond the provision of the home energy report. The report will recommend incentives available through other utility programs based on the customer's energy use profile.	The report will recommend incentives available through other utility programs based on the customer's energy use profile. Participating customers will also receive 6 free CFLs.
Marketing	The report will promote and recommend program and efficiency measures likely to benefit the customer based on individual household energy usage patterns	The report will promote and recommend program and efficiency measures likely to benefit the customer based on individual household energy usage patterns	The paper PER program begins with a letter to the customer offering the paper PER if they return a short energy survey about their home.

		Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
Program Element/ Metric	LG&E/KU	Connexus Energy (Central Minnesota), Home Energy Report Program Start Year: 2008	Duke Energy Kentucky, Personalized Energy Report (PER) Program Start Year: FY2009
Delivery	The Companies will use existing customer data, such as service point information, account information and current energy consumption to develop targeted, customer home energy reports that will be mailed to customers at regular intervals throughout the year (e.g. monthly). Elements that are presented in the report may include a comparison of the customer's home energy use vis-à-vis their peers (residents with similar home/building characteristics), presentation of the customer's current energy use versus their historical use, as well as customized and targeted messages to help the customer reduce energy use. The report will promote and recommend program and efficiency measures likely to benefit the customer based on individual household energy usage patterns.	The program mails a monthly report to participants separate from their utility bill. The report has two parts. The first part compares the customer's monthly energy use against that of their peers (similar households), and against their own historical energy use. The second part includes action steps that suggests behavioral and retrofit measures to reduce customer energy use; these suggestions are targeted to different households based on historical energy use patterns and demographic characteristics.	The customer completes an energy survey and this data is used to generate a personalized energy report based on information the customer provided. The report is either mailed to the consumer or created in real time online. The report evaluates energy usage in the entire home and provides recommendations, many of which are very low cost, to the consumer who may undertake some of these actions.

Discussion of the Companies' versus Others' Programs

The Companies' proposed SEP program is an innovative customer education initiative based on social marketing concepts that have proven successful when applied to other business models.[17] The SEP program is designed after comparable pilot programs implemented by other utilities across the nation that show promising evaluated savings results of approximately two percent average annual savings per participant.[18] The Companies are in the advantageous position of not being the "guinea pig" implementing this innovative program while the program is still "cutting-edge" – to ICF's knowledge, no other IOU in Kentucky has proposed the same program design.

ICF finds that the Companies' proposed SEP program is designed consistent with similar innovative social marketing programs implemented in by other program administrators that have

[17] Research shows the peer pressure is a powerful motivator. The SEP program applies this research by presenting to the test group their home energy use vis-à-vis. that of their "peers" (customers with similar homes).

[18] Note that savings persistence attributable to this program is not well-understood.

resulted in significant, very cost-effective residential energy savings. The Companies' planned costs and savings are reasonable and consistent with that of similar programs.

Connexus' program design and costs are very similar to the Companies' proposed SEP program, as shown in Tables 16 and 17. Note that while Table 15 shows higher first year market penetration for Connexus' program, they are also a much smaller utility than the Companies, totaling 96,000 residential customers. Because of the similarity in program design, we would expect the Companies' program to perform similarly to Connexus', as well to a similar pilot run by the Sacramento Municipal Utility District (SMUD), which also resulted in evaluated annual energy savings of approximately two percent in for the test group receiving the Smart Energy Profile.

Based purely on program design, ICF believes that the Companies' proposed energy report program is superior to Duke's PER pilot. The SEP program will have significant market penetration, which will be challenging for the PER pilot to achieve since participants enroll voluntarily. The SEP program also contains a social marketing component (comparing peer energy use), which research shows has been very effective at reducing customer energy use. Further, the SEP program has a built-in experimental design that helps ensure precise measurement of participant savings.

Conclusions

The Companies' proposed SEP program is innovative and designed for success. In order to help ensure its success, ICF suggests that the Companies follow the best practices listed above. Further, persistence of savings is not well understood for these types of programs; therefore the EM&V plan should include an approach for estimating SEP program savings beyond the first year.

Table 17: Smart Energy Profile Program Results Comparison

Program Element/ Metric	LG&E / KU Year 1	LG&E / KU Year 3	Best Practice Program: Less Mature Market Connexus Energy (Central Minnesota), Home Energy Report 2008-2009	Best Practice Program: More Mature Market Duke Energy Kentucky, Personalized Energy Report (PER) FY2010
Annual Energy Savings MWh	29,664	58,078	12,675	NA
Annual Demand Reduction kW	5,693	11,117	NA	NA
Annual Incentive Costs	$0	$0	NA	NA
Annual Non-Incentive Costs	$1,370,800	$2,240,807	NA	NA
Annual Budget	$1,370,800	$2,240,807	$507,000	$153,000
Participants	105,000	205,000	39,000	NA
kWh/Participant	283	283	325	NA
kW/Participant	0.1	0.1	NA	NA
% Budget incentive costs	0%	0%	NA	NA
% Budget non-incentive costs*	100%	100%	NA	NA
% Budget EM&V	0%	0%	NA	NA
$/1st year kWh	$0.05	$0.04	$0.04	NA
$/1st year kW	$241	$202	NA	NA
Cost/Participant	$13	$11	$13	NA
NTG Ratio	NA	NA	NA	NA
		Source(s):	*Hunt Alcott. Social Norms and Energy Conservation. Departments of Economics and Sloan School of Management, Massachusetts Institute of Technology (MIT). October 2009.*	*Duke Energy. Annual Status Report and Adjustment of the 2009 DSM Cost Recovery Mechanism. Case No. 2009-00444. Filed with the Kentucky Public Service Commission November 16, 2009.* *Hamilton Consulting. Plans for EM&V, Duke Energy.*

**Includes % EM&V costs*

5.2.2. Residential Incentives

Description of the Companies' Program

The Companies' proposed Residential Incentives program will deliver a wide range of energy efficiency measures and services that are cost-effective, but are not included in the Companies' other residential offerings. The program would promote and provide incentives for ENERGY STAR appliances, efficient HVAC equipment, and window film. ICF's understanding is that the Companies are proposing to promote these measures not only because the measures are cost-effective, but because the Companies received feedback from customers that there is demand for these efficient products. The Companies have conducted research on the relevant market channels and end-users and believes that it has sufficient understanding of the market to effectively deliver a program around these measures.

Components of Best Practice Programs

Residential Incentives contains distinct program elements, each of which has unique best practices: these include elements of ENERGY STAR Products-type programs and Efficient HVAC-type programs:

Best practices of programs that promote ENERGY STAR products include:

- Leveraging of the ENERGY STAR brand. This can be achieved by becoming an ENERGY STAR Program Sponsor and/or building public awareness of the ENERGY STAR brand. Activities key to building ENERGY STAR brand awareness include:
    a. Educating retailers and ensuring that ENERGY STAR is promoted on retail floors; and
    b. Developing partnerships with suppliers.
- Spending incentive dollars upstream and midstream, where possible. Such a top-down approach helps transform the market throughout the product stream and makes participation easy for customers through point-of-purchase (instant) rebates.

The following summarizes components of program delivery common amongst best practice residential HVAC programs:

- The use of HVAC contractors as the main vehicle for program deployment. Contractors receive program training and are paid incentives for installing efficient units. This helps keep participation simple for customers. Contractors are also the main delivery method for window film installation.
- Training and education of HVAC distributors;
- Quality Install (QI) training and incentives;
- An AC tune-up element, or cross-promotion with an AC tune-up program; and
- A process for verifying contractor work, including on-site inspections.

Summary of Best Practice Programs

ICF choose three distinct program types to compare to the Companies' proposed Residential Incentives program since the program contains elements of each of these program types, but is not directly comparable to any one program type. The three best practice programs we selected are: San Diego Gas & Electric's (SDG&E) Residential Retrofit Single Family program, the U.S. EPA's Rapid Deployment Energy Efficiency (RDEE) Residential Efficient Heating and Cooling program (which was reviewed as a best practice program by the National Action Plan on Energy Efficiency in the course of EPA's development of the RDEE Toolkit, in spring 2009), and the Residential Retail Products program, which is run jointly by Connecticut Light & Power (CL&P) and United Illuminating (UI).

SDG&E's Residential Retrofit Single Family program is part of a California statewide program effort of the same name. In 2004, the Residential Lighting and Home Energy Efficiency Rebates (HEER) Programs were combined to form the Statewide Single-Family Energy Efficiency Rebate (SFEER) Program to streamline internal operations for the utilities. The SFEER Program includes a diverse array of energy efficiency measures including home improvement products, heating and cooling equipment, lighting, appliances, and pool equipment. The 2004-2005 Program targeted all residential customers paying a Public Goods Charge and residing in dwellings of four units or less, including condominiums and mobile homes.[19]

The objectives of the RDEE Residential Efficient Heating and Cooling program are to increase sales of efficient (ENERGY STAR qualified, or better) heating and cooling equipment in replace-on-burnout, retrofit, and new construction opportunities, and to improve the operating efficiency of equipment through tune-ups of existing units and Quality Installation (QI) of new units. HVAC contractors are the main vehicle for deployment of this program. Contractors must complete trainings for AC tune-ups (refrigerant charge, coil cleaning, filter change, and a blower speed test), AC quality installation (proper sizing, refrigerant charge, and air flow test), furnace quality installation (proper sizing, air flow adjustment, furnace on-rate check), and other program requirements.[20]

CL&P and UI's Residential Retail Products program is essentially an ENERGY STAR Products program than provides incentives for CFLs and ENERGY STAR appliances. In both the lighting and appliances segments, the program uses Negotiated Cooperative Promotions (NCPs), which the Companies' find to be a successful approach to increase stocking and sales of efficient products at considerably lower cost than traditional coupons and rebates. NCPs involve partnerships between the program and retailers and manufacturers and are structured with underlying memoranda of understanding (MOUs) that tie payment of incentives to the Companies' receipt of store-level sales data.[21]

[19] Itron. 2004/2005 Statewide Residential Retrofit Single-Family energy Efficiency Rebate Evaluation. October 2, 2007.
Best Practice Benchmarking for Energy Efficiency Programs. Summary Profile Report. CA Single Family EE Rebates. http://www.eebestpractices.com/Summary.asp?BPProgID=R24E.
San Diego Gas & Electric Company – Statewide residential Single Family Home Energy Efficiency Rebates (PGC) – SDGE service area – IOU Statewide Program – Jan-06 Report.

[20] U.S. EPA. Rapid Deployment Energy Efficiency Toolkit, Planning and Implementation Guides. October 2009.

[21] Connecticut Light & Power and United Illuminating. 2009 Conservation and Load Management Plan. October 2008.

Table 18: Residential Incentives Program Comparison

Program Element/ Metric	LG&E / KU	Best Practice Program: Market Maturity High San Diego Gas & Electric (Sempra); Residential Retrofit Single Family Program Program start year: 2001	Best Practice Program: Market Maturity Mid U.S. EPA, Rapid Deployment Energy Efficiency (RDEE) Toolkit, Residential Efficient Heating and Cooling Program Program start year: NA	Best Practice Program: Market Maturity Mid-to-Low Connecticut Light & Power and United Illuminating, Residential Retail Products Program start year: 2000
Program Objective(s)	Encourage customers to purchase various ENERGY STAR products, HVAC equipment and window films.	Achieve energy savings and demand reduction.	The objectives of this program are to increase sales of efficient (ENERGY STAR qualified, or better) heating and cooling equipment in replace-on-burnout, retrofit, and new construction opportunities, and to improve the operating efficiency of equipment through tune-ups of existing units and quality installation of new units.	Build awareness, acceptance and market share of ENERGY STAR lighting, appliances and electronics.
Target Market(s)	Residential	All residential customers paying a Public Goods Charge and residing in dwellings of four units or less, including condominiums and mobile homes.	This program targets HVAC contractors and homeowners with central air conditioners and furnaces.	Residential
Market Penetration	Build to 20,500 rebates per year by Year 3	NA	4% after 3 years	2,409,313 (units)
Measures	HVAC, ENERGY STAR appliances, window films.	HVAC, lighting, appliances, home improvement products, pool pumps.	ENERGY STAR Heating and Cooling equipment. AC Tune-ups. Quality Install (QI) of HVAC units.	ENERGY STAR lighting (CFLs), appliances, and electronics
Incentive Structure	Incentives will be paid directly to customers via mail-in rebates.	Lighting, upstream (manufacturers). Appliances, midstream (retailers). HVAC, midstream (installation contractors).	Incentives paid mid-stream to HVAC contractors (typically 50-75% of measure incremental costs)	Point of purchase and mail-in rebates.

		Best Practice Program: Market Maturity High	Best Practice Program: Market Maturity Mid	Best Practice Program: Market Maturity Mid-to-Low
Program Element/ Metric	LG&E / KU	San Diego Gas & Electric (Sempra), Residential Retrofit Single Family Program Program start year: 2001	U.S. EPA, Rapid Deployment Energy Efficiency (RDEE) Toolkit: Residential Efficient Heating and Cooling Program Program start year: NA	Connecticut Light & Power and United Illuminating, Residential Retail Products Program start year: 2000
Marketing	Marketing will include retailer training and point-of-purchase displays, among other activities and collateral. A full marketing plan will be developed pending program approval.	Bill inserts direct mail, newspaper and radio advertising, email blasts, community events, and information from their web sites and phone centers. The IOUs also coordinated with market actors including manufacturers, distributors, retailers, contractors, and others.	Consumer collateral. Program Web site. HVAC contractor & distributor recruitment and training. Call center.	Direct mail. Publications in community and business newsletters. Attendance at ENERGY STAR sales events. General promotion of the ENERGY STAR label.
Delivery	The Companies will hire, through an RFP process, a 3rd party contractor to develop the appropriate application and documentation supporting customer purchases, provide QA/QC of rebate applications, and process rebate checks. All documentation will be submitted to the Companies for auditing and data retention. The Companies will have customer verification/audit rights as well.	For lighting, the program worked with lighting manufacturers to buydown the cost of CFLs. For appliances, the program worked with manufacturers to buydown the cost of the units in some areas; mail in rebates were used otherwise. For HVAC measures, the program worked with HVAC contractors, who received training and were paid incentives.	HVAC contractors are the main vehicle for deployment of this program.	Midstream and upstream partnerships with retailers and manufacturers - Negotiated Cooperative Promotions (NCPs).

Discussion of the Companies' versus Others' Programs

In general, ICF finds that Companies' analytical methodology leading to this proposed program is sound and consistent with our own experience planning similar programs in other jurisdictions, including Louisiana, Maryland, and Wisconsin. Further, ICF finds that the Companies' planned costs and savings are reasonable and appropriate for a new program of this nature operating in a relatively immature market.

Residential Incentives contains some distinct elements of best practice programs described above. There are many models for delivering residential programs of this nature; some utilities combine all program elements into an umbrella residential mass market program that includes lighting, HVAC, appliances, and home performance; others include each of these as distinct programs; some utilities combine lighting and appliances into one ENERGY STAR Products program. Ultimately, each utility needs to package and market its programs in a manner that results in the most cost-effective savings that can be achieved within its own territory. The packaging usually changes over time as markets and technologies evolve; this is a key reason why it is important for program administrators to retain flexibility in how they deliver their programs.

While ICF could not find one program exactly comparable to the Companies' proposed Residential Incentives initiative, this is only because the Companies are packaging particular elements of their residential portfolio differently from other utilities. Further, the Companies' cost and savings assumptions, which ICF reviewed and finds reasonable, show the program is cost-effective.

Conclusions

ICF suggests the Companies consider the following possible strategies for delivering each component of the proposed Residential Incentives program.

1. Coordinate and cross-promote the new HVAC equipment rebates together the existing AC tune-up program. This would allow the Companies to capitalize on their existing relationships with AC contractors developed through the AC tune-up program.
2. Coordinate and cross-promote the appliance rebate and window film elements of the Residential Incentives initiative with the existing Residential High Efficiency Lighting program. This could allow new Residential Incentives elements (appliance, window film) to be co-branded along with CFLs, and allow the Companies to capitalize on existing retailer relationships achieved through the current CFL program. If the Companies plan on promoting window film as a low-cost DIY measure that will eventually replace some portion of CFL savings, window film should be promoted, where possible, in the same retail channels as CFLs (e.g. Lowe's, Home Depot, hardware stores).

Table 19: Residential Incentives Program Results Comparison

			Best Practice Program: Market Maturity High	Best Practice Program: Market Maturity Mid	Best Practice Program: Market Maturity Mid-to-Low
Program Element/ Metric	LG&E / KU		San Diego Gas & Electric (Sempra), Residential Retrofit Single Family Program 2004-2005	U.S. EPA, Rapid Deployment Energy Efficiency (RDEE) Toolkit, Residential Efficient Heating and Cooling Program 2009	Connecticut Light & Power and United Illuminating, Residential Retail Products Program start year: 2007
	Year 1	Year 3			
Annual Energy Savings MWh	8,544	16,291	CFLs: 60,457 (net) Non-lighting: 2,672 (net)	NA	62,000
Annual Demand Reduction kW	1,477	3,042	CFLs: 4,450 (net) Non-lighting: 1,257	NA	968
Annual Incentive Costs	$942,500	$1,772,500	$6,254,533	NA	$4,438,000
Annual Non-Incentive Costs	$642,852	$873,230	$1,907,380	NA	$1,524,000
Annual Budget	$1,567,352	$2,645,730	$8,161,914	NA	$5,962,000
Participants	11,700	20,500		10,000	2,409,313
kWh/Participant	730	795	NA	2,000 (varies by climate zone and fuel type)	26
kW/Participant	0.1	0.1	NA	0.2 (varies by climate zone)	<.01
% Budget incentive costs	60%	67%	77%	60%	74%
% Budget non-incentive costs*	40%	33%	23%	40%	26%
% Budget EM&V	5%	2%	3%	4%	NA
$/1st year kWh	$0.18	$0.16	$0.08	$0.17	$0.10
$/1st year kW	$1,061	$870	$470	$1,900	$6,159
Cost/Participant (rebate)	$134	$129	NA	$400	$2
NTG Ratio	0.87 (average across all measures types)		CFLs: 0.62 Non-lighting: 0.56	0.80	NA

			Best Practice Program: Market Maturity High	Best Practice Program: Market Maturity Mid	Best Practice Program: Market Maturity Mid-to-Low
Program Element/ Metric	LG&E / KU		San Diego Gas & Electric (Sempra), Residential Retrofit Single Family Program 2004–2005	U.S. EPA Rapid Deployment Energy Efficiency (RDEE) Toolkit, Residential Efficient Heating and Cooling Program 2009	Connecticut Light & Power and United Illuminating, Residential Retail Products Program start year: 2007
	Year 1	Year 3			
*Includes % EM&V costs		Source(s)	*Itron. 2004/2005 Statewide Residential Retrofit Single-Family energy Efficiency Rebate Evaluation. October 2, 2007* *Best Practice Benchmarking for Energy Efficiency Programs. Summary Profile Report. CA Single Family EE Rebates http://www.eebestpractices.com/Summary.asp?BPProgID=R24E. Retrieved 11-09* *San Diego Gas & Electric Company – Statewide residential Single Family Home Energy Efficiency Rebates (PGC) – SDGE service area – IOU Statewide Program – Jan-06 Report*	*U.S. EPA. Rapid Deployment Energy Efficiency Toolkit, Planning and Implementation Guides. October 2009.*	*Connecticut Light & Power and United Illuminating. 2009 Conservation and Load Management Plan. October 2008.*

5.2.3. Residential Refrigerator Removal

Description of the Companies' program

The objectives of the Companies' proposed Residential Refrigerator Removal program are to remove and recycle old and inefficient working secondary refrigerators and freezers from the grid, and to reduce environmental impacts associated with improper appliance disposal. The Companies' proposed program is based on a proven, cost-effective program design that has been run successfully by numerous program administrators around the country.

Components of Best Practice Programs

The following summarizes components of program delivery common amongst best practice residential appliance recycling programs; best practice programs:

- Partner with an experienced appliance recycling company who can provide cost-effective, turn-key program services.
- Have procedures in place (e.g., random inspections) to ensure that participants' units are working and in-use prior to pick-up.
- Ensure that scheduling is made simple for customers and that pick-ups are timely.
- Cross-promote other utility programs.
- Plan with evaluators early to ensure they have access to an appropriate sample of units for data logging.

Summary of Best Practice Programs

ICF chose two existing programs to compare against the proposed program: Oncor's Refrigerator Round-Up program, and Southern California Edison's (SCE) Appliance Recycling program. These programs represent best practice in program implementation in two different energy efficiency markets, one more mature (California) and one less mature (Texas). Both these programs partner with appliance recycling companies who provide turn-key program services, including:

- Scheduling
- Pick-up
- Recycling
- Program tracking
- Incentive fulfillment
- Assistance with program marketing

Oncor partners with the Appliance Recycling Centers of America (ARCA) to implement the Refrigerator Roundup program, which launched in 2004. The program offers an incentive of $50 per working unit to customers. In 2008, the program recycled nearly 5,000 refrigerators and freezers in the Dallas region.

SCE's Appliance Recycling Program launched in 1994, and partners with both ARCA and JACO Environmental to manage the program's recycling services. This program removes over 100,000 old units from the grid in the Southern California region every year.

Table 20: Residential Refrigerator Removal Program Comparison

		Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
Program Element/ Metric	LG&E / KU	Oncor, Refrigerator Round-up Program Start Year: 2004 Data year(s): 2008	Southern California Edison, Appliance Recycling Program Program Start Year: 1994 Data year(s): 2004-2005
Program Objective(s)	Remove and recycle old and inefficient working secondary refrigerators and freezers from the grid. Reduce environmental impacts associated with improper appliance disposal.	Remove operating spare refrigerators and freezers from customers' homes.	Reduce customer bills. Remove inefficient units from the grid. Reduce CFC emissions. Eliminate "hassle factor" of removing appliance(s) for customers.
Target Market(s)	Residential	Residential	Residential and small business
Market Penetration	*Build to 10,000 units per year* by Year 3	*4,900 units recycled*	*120,000 units recycled*
Measures	Refrigerator and freezer removal and recycling	Refrigerator and freezer removal and recycling	Refrigerator and freezer removal and recycling; limit of 2 units per customer per year; window ACs also eligible
Incentive Structure	$30 per working unit	$50 per working unit	$35 per working unit (note: this amount was increased to $50/unit in 2006)
Marketing	Targeted direct mail; full marketing plan developed	Direct mail, website, mass media, appliance dealers	Direct mail, media outlets; website, appliance dealers
Delivery	Turn-key program implementation through appliance recycling company.	Turn-key program implementation through appliance recycling company.	Turn-key program implementation through appliance recycling company.

Discussion of the Companies' versus Others' Programs

The Companies' proposed program is very similar in design to the example programs, as shown in the table below.[22] The Companies propose that an established appliance recycling company will provide turn-key program services. All similar programs use this program delivery method, to ICF's knowledge. There are only two major appliance recycling companies in the U.S. who are experienced at working with utilities on efficiency programs. The Companies will benefit from lessons learned by either of these firms should it move forward with this initiative.

[22] ADM Associates et al. Evaluation of the 2004-2005 Statewide Residential Appliance Recycling Program. Final Report. April 2008. Southern California Edison – Residential Appliance Recycling – SCE service area – IOU Statewide Program – Jan-06 Report

At this planning stage, the only difference between the proposed program and the example programs' is the incentive level. The Companies' proposed incentive is somewhat lower than incentives offered by other utilities; however ICF believes that the Companies' proposed incentive is appropriate in initial program years within the Companies' territory, which is a relatively immature market for energy efficiency. Because the program has not been offered before, customers will likely find an incentive of $30 for removing and properly disposing of their old appliance to be an attractive offer. Note that SCE' per unit incentive in 2004-2005 was $35, when the program was new, and was increased in subsequent years.

In general, ICF finds that the Companies' planning assumptions for program costs and savings are reasonable and appropriate. As shown below, based on The Companies' proposed program costs and net savings estimates, The Companies' program will cost approximately $0.27 per kWh in Year 1, which is similar to the net cost of SCE's program; Oncor's cost per kWh is somewhat lower, although Oncor's savings estimates do not include free-riders (which, if included, would drive cost-effectiveness down). The Companies' total cost per unit ($204) is also higher than SCE's ($158), though not unreasonably high.[23]

Conclusions

The Companies' proposed Refrigerator Recycling program contains many elements of best practice programs and the planned cost and savings are reasonable for such a program entering a relatively immature market. Although we believe the program plan generally reflects best practices, below, ICF provides some suggestions for The Companies' consideration

1. Establish a procedure for ensuring program compliance. The primary concern here is ensuring that the vendor is paying incentives only for working units.
2. Work with an evaluator from the start. Typically, program savings are estimated through a combination of data logging and participant and non-participant surveys. The evaluator will need to work with the recycling vendor to have a sample of units set aside for data logging.
3. Cross promote other programs. This program results in customer contacts at a number of points in the participation process, each of which provides an opportunity to promote other efficiency programs; one obvious synergy is the Residential Rebate program, which rebates ENERGY STAR appliances, including refrigerators and freezers.

[23] ADM Associates et al.

Table 21: Residential Refrigerator Removal Program Results Comparison

Program Element/ Metric	LG&E / KU		Best Practice Program: Less Mature Market	Best Practice Program: More Mature Market
	Year 1	Year 3	Oncor, Refrigerator Round-up Program Start Year: 2004 Data year(s): 2008	Southern California Edison, Appliance Recycling Program Program Start Year: 1994 Data year(s): 2004-2005
Annual Energy Savings MWh	3,000	7,500	7,131 (gross)	120,949 (net)
Annual Demand Reduction kW	339	849	1,100 (gross)	NA
Annual Incentive Costs	$120,000	$300,000	$471,416	NA
Annual Non-Incentive Costs	$695,800	$1,655,829	$89,316	NA
Annual Budget	$815,800	$1,955,829	$560,732	NA
Participants	4,000	10,000	4,900 (units)	
kWh/Participant	750	750	1,466 per refrigerator (gross; 1,701 per freezer (gross)	1,776 per refrigerator (gross; 1,415 per freezer (gross)
kW/Participant	0.1	0.1	0.26 per refrigerator (gross; 0.18 per freezer (gross)	NA
% Budget Incentive Costs	15%	15%	84%	88%
% Budget Non-Incentive Costs	85%	85%	16%	12%
% Budget EM&V	0%	0%	NA	3%
$/1st Year kWh	$0.27	$0.26	$0.16	$0.22
$1st Year kW	$2,414	$2,304	$956	$1,298
Cost/Participant	$204	$196	$114 per unit	$158 per unit
NTG Ratio	1.00	1.00	NA	0.72
*includes %EM&V costs		*Source(s):*	*Oncor 2009 Energy Efficiency Plan and Report. April 1, 2009*	*ADM Associates, et al. Evaluation of the 2004-2005 Statewide Residential Appliance Recycling Program. Final Report, April 2008. Southern California Edison – Residential Appliance Recycling – SCE Service Area — IOU Statewide Program — January 2006 Report*

6. Overall Conclusions

Our review of the Companies' portfolio, and the context in which they were developed, leads us to the following conclusions:

- The Companies' proposed portfolio is consistent with evolving federal and state policies. In addition, the portfolio contains many elements of best practices, including cost-effectiveness, broad targeting, and flexible design.
- The Companies should commission a potential study or market characterization study, an action item the governor has also proposed for the state in his energy plan. The study results could be used to help plan programs that capture savings where potential is greatest and/or most cost-effective.
- Based on a market characterization study of the commercial sector, the Companies should develop additional programs targeting the commercial sector. Though the Companies continue to offer cost-effective programs, the portfolio could improve its cost-effectiveness through additional commercial programs. These could be achieved through the continuation of proven program types related to lighting, HVAC, and motors measures, or through the identification and targeting of customers interested in custom projects.

Our review of the Companies' proposed programs leads us to the following conclusions:

- Load Control Management - The Companies currently operate a successful load control program for residential and commercial customers, and are appropriately proposing to increase incentives to increase participation. The Companies should also consider and promote additional program options that would result in greater participation, lower program unit costs, and greater cost-effectiveness. Examples of these options include an enhanced incentive structure (that targets larger and high-use customers), multiple control options, and a real-time pricing element. In addition, because the program has significant market penetration, the Companies can use points of contact with these current participants to market other programs. In addition, the Companies' experience with demand response programs will help to develop a successful and cost-effective strategy for any eventual AMI deployment.

- Commercial Conservation / Commercial Incentives - The Companies should ensure that the audits are comprehensive and are continuing to motivate customers to participate in the program. In addition, the Companies should monitor the incentive structure and participation to ensure a broad mix of customer participation, which will result in cost-effective savings and achievement of program goals. The Companies should also continue to add prescriptive measures and work with trade allies to ensure their continued participation with and promotion of the program. In the future, the Companies should consider incorporating the EPA's Portfolio Manager benchmarking tool to provide customers with ongoing and post-project information regarding facility usage and savings. Since this initiative requires investment in equipment and personnel, the Companies should implement it once the expanded program has been running for a few years. This will allow the tool to be applied to a larger participant base, and ensure greater persistence of energy savings.

- Residential Conservation/Home Energy Performance program - The Companies should continue to consider Program Sponsorship through the EPA, in order to take advantage of existing resources and expand program participation. The Companies should also consider

EXHIBIT

Energy Efficiency Resource Standards: State and Utility Strategies for Higher Energy Savings

Seth Nowak, Martin Kushler, Michael Sciortino, Dan York, and Patti Witte

June 2011

Report Number U113

529 14th Street, N.W., Suite 600, Washington, D.C. 20045
(202) 507-4000 phone, (202) 429-2248 fax, www.aceee.org

SC\NRDC EXHIBIT 10

CONTENTS

ACKNOWLEDGMENTS

We thank Southern California Edison, Pacific Gas & Electric, Commonwealth Edison, NYSERDA, and National Grid for funding this project.

We are grateful to the following leading energy efficiency industry experts for providing interviews and sharing their deep knowledge and broad perspectives:

Ed Vine, Lawrence Berkeley National Laboratory
Jeff Schlegel, independent consultant
Chris Neme, Energy Futures Group
Doug Baston, Atlantic Energy Advisors
Tim Stout, E-Source
Dave Hewitt, New Buildings Institute
Howard Geller, Southwest Energy Efficiency Project

We also thank Ed Vine, Doug Baston, Val Jensen, George Malek, Liz Hanna, and Sarah Osgood for helpful comments on drafts of this report. Furthermore, we thank the many contacts at utilities, state governments, and nonprofit organizations, too numerous to list here, who participated in interviews and shared their knowledge and insights on program responses to aggressive savings targets, many of whom also reviewed draft case studies.

Finally, thank you to ACEEE colleagues Steven Nadel, Rachel Gold, Glee Murray, Patrick Kiker, and Renee Nida for their assistance in the research, review, production, and release of the report.

EXECUTIVE SUMMARY

Energy efficiency programs funded by and serving energy utility customers are now widespread. With roots in the energy crises of the 1970s, such programs have grown, endured, and evolved against a backdrop of many fundamental industry and broader economic changes. A majority of states have established specific policies that set specific energy savings targets for energy efficiency programs provided to customers by their utilities or related organizations. These policies, called "energy efficiency resource standards" (EERS), are driving programs to ramp up to achieve and sustain unprecedented levels of energy savings compared to historic achievements. Numerous studies of energy efficiency "potentials" over the years have portrayed a large, low-cost reserve of energy savings that could be captured through more widespread adoption of energy-efficient technologies, practices, and behaviors.

Many of these new state EERS policies have established energy savings requirements that are quite challenging. In some cases, well-established programs must double or even triple historical savings. In other cases, states with relatively little historical experience with large-scale energy efficiency programs have established similarly large energy savings goals over time (e.g., as much as 1.5% or 2% savings per year after a period of ramp-up). ACEEE conducted research on a selection of both types of states, six "Established Savers" and six "Rapid Starts," to review their progress towards meeting EERS goals and examine how the programs are responding to this challenge. We interviewed program managers, regulatory staff, consultants, and other energy efficiency experts for this research. We also reviewed selected program documentation and data.

Despite different starting points and backgrounds, states in each of those two categories are following a variety of common key strategies to achieve high savings. The distinction of being an "Established Saver" or "Rapid Start" seems mostly to affect practical implementation details and degree of emphasis on any of these strategies. Established Savers benefit from having their infrastructure in place and from having long experience with programs; however, they also have to reach beyond existing levels of achievements and into new territory. High numbers of customers in these states typically already have participated in programs. To achieve greater savings thus means reaching customers who have not participated before or moving previous participants to implement additional measures. Rapid Starts, by contrast, do not have the benefit of long-established programs, but on the other hand, are targeting customers who have not necessarily done much in the way of energy efficiency improvements. Thus, there is a large, untapped, low-cost reserve of energy efficiency opportunities to access through programs.

Key strategies that these states are utilizing in their efforts to achieve high savings include:

- *Increasing program funding.* Expanding, enhancing, and developing new programs require more resources. This is acknowledged as a fundamental requirement in order to achieve greatly enhanced savings impacts. Moreover, it is possible that reaching savings beyond historic levels may be more expensive per unit of saved energy as there are less of the easiest, lowest cost resources (the "low-hanging fruit") available.

- *Establishing supportive utility regulatory policies.* The financial disincentives for saving energy through improved energy efficiency become much more pronounced for utilities as the magnitude of such savings increases in response to higher EERSs. All leading states have instituted regulatory changes designed to align utility financial incentives with energy efficiency program objectives.

- *Establishing complementary policies to capture non-program savings.* While energy efficiency programs provided to utility customers (whether by utilities or related organizations) are the primary vehicles for reaching high savings, there are numerous related policies that can contribute to achieving overall state savings targets. These include building codes, appliance standards, state government procurement, and combined heat and power. Many state EERS include provisions for such complementary activities to contribute to reaching prescribed savings goals.

- *Involving stakeholders in collaborative processes for program development and implementation.* Building relationships among key stakeholders, which include customers, manufacturers, contractors, trade associations, advocacy groups, regulators, and government authorities, is critical for effective program design and implementation. The products and services provided or supported through energy efficiency programs must appeal to customers and deliver real benefits.

Key strategies that utility program administrators are employing to fulfill resource standards include:

- *Identifying and prioritizing targeted technologies and end-uses.* The roles played by lighting and compact fluorescent lamps (CFLs) continue to be major considerations, as Established Savers shift resources toward new and more diverse lighting technologies while programs in Rapid Start states rely more heavily on CFL savings to meet the demands of increasing annual EERS levels.

- *Developing programs capable of delivering "deep" savings first, then seeking "broad" participation.* Increasing overall program savings in states that have had extensive efficiency portfolios for many years cannot be accomplished cost-effectively simply by expanding participation in existing programs. Program designs are being initiated that are capable of capturing more savings for each participating customer. This generally means customers must enact more measures, with greater incremental efficiency gains, to achieve "deep" savings.

- *Creating programs for new and emerging technologies.* Today's pace of technological change is rapid and accelerating. This affects customer markets and technological choices, as well as programs and services available to customer. Significant changes are occurring in such areas as lighting, HVAC, electronics, communications, and data systems. Many of these technological advances represent new energy savings opportunities that program administrators are seizing today and preparing to integrate into their portfolios within the timeframe of most of these state EERS requirements.

- *Extending portfolios with programs to reach new and under-served markets.* There are a number of customer markets that have not been as well served in the past as others have been, such as tenant fit-ups in commercial spaces, in which the premises are customized to match tenant needs and uses. New markets (such as computer data centers) and new approaches (such as behavioral programs) have recently emerged. Program administrators must examine such markets and approaches and ensure that programs are developed and available that can effectively serve these customers to deliver additional savings.

- *Taking on innovative advertising and promotional channels and increasing incentives to raise customer participation.* In Established Savers states, program administrators continue to enhance and extend programs to reach more participants. They are doing more advertising, finding ways to make participation easier and more convenient (especially through upstream and midstream lighting and appliance incentives), and offering higher rebates to more customers. In early program years, some new programs have overshot the mark and had to reduce rebates to conserve funds to meet consumer demand.

Leading industry experts and program managers agree that if the funding and political will are there, energy utilities will continue to develop, evolve, and extend efficiency programs to meet the standards.

Some early results presented here show that these twelve states are obtaining higher energy savings. Most utility respondents were optimistic that they would continue to meet annual standards in years to come.

OBJECTIVES AND SCOPE OF THE REPORT

A majority of states now have policies in place that establish specific energy savings targets for energy efficiency programs provided to customers by their utilities or related organizations. These policies—called "energy efficiency resource standards" (EERS)—are analogous to "renewable energy standards," which are also in place across a majority of the states. EERS have been enacted largely to accelerate and expand the scale of energy savings achieved through utility energy efficiency programs, primarily at large investor-owned utilities, but also at publicly-owned and cooperative utilities. The key break from the past is that these standards are set at savings levels that require more savings to be achieved through these programs than ever before—and not only having to reach these savings once, but also having to sustain and even increase these savings over time.

Numerous studies of energy efficiency "potentials" over many years have overwhelmingly portrayed a significant amount of savings that could be achieved through improvements in energy efficiency of our buildings and industries (McKinsey & Company 2009, National Academy of Sciences 2010). While such studies suggested a relatively large, untapped potential, actual amounts of annual energy savings achieved by utility and related programs historically have remained rather small—fractions of a percent of annual sales. Until recently, achieving annual savings of about 1% of annual energy sales was a rare achievement—and even today there are few states that have achieved this benchmark savings. Typically, long-standing, well-established programs may have achieved annual savings from about 0.5% to 0.7 percent of annual energy sales. This picture is changing rapidly, however, as an increasing number of states are pushing towards unprecedented savings levels—changes driven largely by EERS.

EERS have been enacted in states with long-standing, comprehensive programs and in states where such programs have been lacking. The starting points for achieving high savings levels are, therefore, much different in these two groups of states. States with long-running, full portfolios of programs can build upon strong infrastructures and experiences running customer energy efficiency programs. However, their past success can mean that they have already reached many customers and associated applications for implementation of energy-efficient technologies. This can mean these programs have to work harder to reach new customers as well as achieve "deeper" savings for each participating customer—that is, getting each customer to enact a larger set of energy efficiency measures than in the past. States that have not had customer energy efficiency programs in place lack the existing infrastructure and experience, but they also may be able to capture significant initial savings from essentially an untapped resource—energy efficiency measures that yield high savings relative to costs, and that are relatively easy to implement.

As a result of these differences in starting points, this study has a framework that features two categories of EERS states: "Rapid Start" (states with relatively little pre-existing energy efficiency programs and infrastructure) and "Established Saver" (states with well-established and relatively large-scale pre-existing energy efficiency programs and infrastructure).

This report examines the experiences of both kinds of states in responding to the challenges faced by their energy efficiency programs—whether provided by publicly-owned utilities, investor-owned utilities, or related "public benefits organizations"—in reaching the savings as established in EERS.[1] We interviewed program managers and other key stakeholders about how their programs are planning to reach high energy savings. We conducted most interviews with representatives from the largest investor-owned utilities with the largest efficiency portfolios. Input from these individuals does not necessarily represent efficiency program trends in rural electric cooperatives or municipal electric and gas utilities.

We also interviewed a set of national experts on program design, implementation, and evaluation for their perspectives on how customer energy efficiency programs as provided by utilities and related organizations are evolving and changing to meet new goals.

[1] ACEEE's concurrent publication, *Energy Efficiency Resource Standards: A Progress Report on State Experience* (Sciortino et al. 2011), systematically reviews the early results for every state with an EERS in effect for two or more years, or twenty of the twenty-six EERS states.

The objectives of this report are:

- Document the EERS policies being enacted to establish high energy savings goals and the utility and public benefits energy efficiency programs being undertaken to meet them;
- Examine the similarities and differences in such changes between programs in states with long-standing, well-established programs and in states that only recently initiated significant customer energy efficiency programs;
- Identify key program strategies and designs being pursued to reach high savings levels;
- Assess relative progress in meeting initial goals and present initial results;
- Identify and discuss key challenges being encountered and lessons learned;
- Examine trends and prospects for reaching and sustaining maximum savings levels prescribed in EERS; and
- Discuss complementary and supportive policies.

BACKGROUND

To understand this most recent energy efficiency policy mechanism (EERS), it is helpful to have some background and context regarding the history of utility energy efficiency efforts. Utility-sector energy efficiency policies have been characterized (Kushler et al. 2006) as having evolved through at least four major phases, as briefly described below.

- *The 1970s Energy Crisis Era:* The first utilities to offer programs to help customers reduce energy use began their efforts in the 1970s, after the initial 1973 oil embargo. These programs were primarily intended to help customers cope with soaring energy prices by providing them with programs to help lower their utility bills. These programs were found to be quite popular with customers, and spending on and savings of utility energy efficiency programs ramped up on into the 1980s.

- *The IRP Era:* In the mid- to late 1980s, the concept of utility integrated resource planning (IRP) emerged, which introduced the concept of demand-side management (DSM) and particularly accelerated the use of energy efficiency as an electric system resource. Electric utility energy efficiency spending grew steadily throughout this period, peaking at over $1.8 billion in 1994.

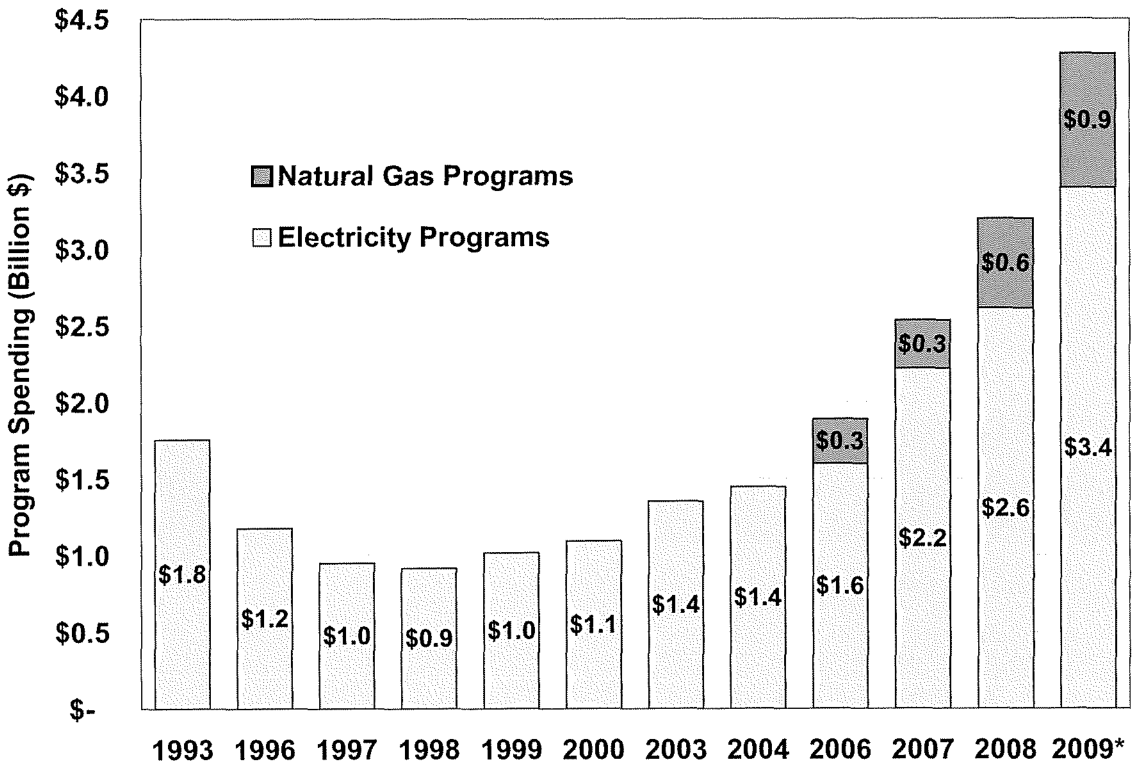
- *The Restructuring/Public Benefits Era:* Just as utility energy efficiency spending was accelerating, the electric industry "restructuring" movement was launched in 1994 and quickly spread across the nation. Unfortunately, for a variety of reasons, restructuring created economic pressures that tended to cause utilities to reduce or abandon energy efficiency programs. In addition, the move toward more limited regulation under restructuring tended to weaken or eliminate prior mechanisms that had helped facilitate energy efficiency, such as IRP. Nationwide, annual electric utility energy efficiency spending plunged by over 50% from 1994 to 1997 (York and Kushler 2005).

  In recognition of these adverse effects of restructuring on energy efficiency, many states included in their restructuring policy the creation of a "public benefits" funding mechanism, to continue some level of energy efficiency programming. The rationale for these programs was not to provide electric system resources (the "market" was to be responsible for that), but rather, to ensure that the beneficial effects of energy efficiency for the public (including environmental benefits) would not be lost. Arguably, the strategy of "public benefits" energy efficiency "saved" the concept of utility-sector energy efficiency and was able to begin to reverse the downward trend in utility energy efficiency spending, beginning in the post-1998 time period.

- *The Resource Procurement Era:* By the late 1990s, there were growing incidents of electric system reliability problems in several regions, culminating with the massive California/West Coast electricity crisis of 2001. These events tended to re-focus attention on the role of utility-sector energy efficiency as a system resource, a notion that had fallen out of favor during the restructuring era.

As the first decade of the 21st Century unfolded, rapidly rising energy fuel costs and dramatic increases in power plant construction costs added urgency to the call for energy efficiency as a serious utility system resource. During that decade, funding for energy efficiency programs rose rapidly from the low point of the 1990s. Total funding for energy efficiency programs was $5.5 billion in 2010. Figure 1 traces the trends in energy efficiency program expenditures for the period 1993–2009.

Figure 1. U.S. Electricity and Natural Gas Energy Efficiency Program Spending or Budgets by Year, 1993–2009



* Includes ratepayer-funded programs. All values are actual program spending except for 2009, which are budgets. Natural gas efficiency program spending is not available for 1993–2004. Sources: Nadel et al. (2000); York and Kushler (2002, 2005); Eldridge et al. (2008, 2009)

This tremendous and rapid growth has been driven both by utility system resource needs and by the demonstrated low cost and value of energy efficiency as a means to reduce costs for customers and utilities, while providing benefits to the environment and public health, as well as meeting other public policy goals. The value of energy efficiency has been repeatedly demonstrated by regular, robust evaluations of these programs. The cost to utilities of saving electricity through utility energy efficiency programs has consistently been found to be in the range of about 2.5 to 3.0 cents per kilowatt-hour.[2] This is about one-fourth to one-third the cost of generating a kilowatt-hour by conventional fossil fuels in new power plants.

[2] For example, ACEEE reviewed the results reported by 14 states with major energy efficiency programs and found an average cost of conserved electricity of 2.5 cents per kWh (Friedrich et al. 2009).

Increasing concern for the environment also has played a role in this growth since reducing energy use through improved energy efficiency can greatly reduce emissions of airborne pollutants from power generated by fossil fuels, including greenhouse gases.

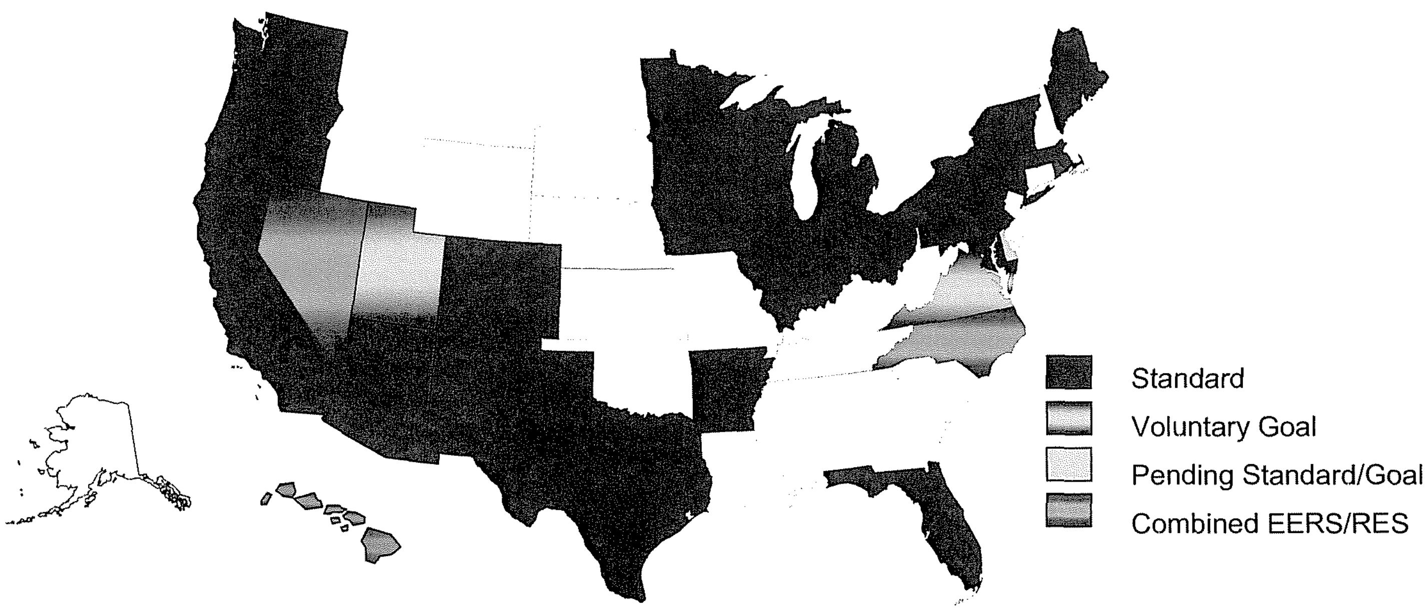
Energy Efficiency Resource Standards: Policies Driving Higher Savings

This new policy tool has arisen over the past decade in conjunction with the rebuilding and expansion of utility energy efficiency programs. An EERS establishes specific savings targets (expressed typically as a percentage of energy sales or specific energy units, such as therms of natural gas or kilowatt-hours of electricity) on a specific timetable. They are analogous to a "renewable energy standard," which are common among states across the U.S. In this manner, programs are driven by meeting established targets. Historically such goal-driven approaches have not necessarily been the norm for how programs have been developed and funded. In many cases program budgets have been a starting point; the amount of savings achieved then became more of a function of the initial budgets; cost-effectiveness screening of measures and programs; and finally implementation of the programs. Savings were an outcome, not necessarily the primary driver of program development and implementation.

Texas was the first state to establish an EERS, which happened in 1999 for energy efficiency programs offered by the electric utilities. Since then, 25 more states have put in place some type of EERS for electricity. Twelve states also include such standards for natural gas, and there are pending standards in a few other states.

The development of EERS is significant because these savings targets generally are set at levels that are pushing programs to achieve higher savings than they may have ever achieved prior to their enactment. Not only are EERS pushing the programs to achieve high savings, but they also seek to sustain such high savings levels over a span of many years. To meet and sustain these goals generally will require both adaptations to existing programs and development of new programs and innovative approaches to reach and serve more customers. Programs will have to achieve more savings per participating customer as well as reach customers who have not participated in past programs.

Figure 2. State Energy Efficiency Resource Standard (EERS) Activity
(As of January 2011)



See Appendix A for description of individual state EERS.

METHODOLOGY

We selected states from among the 26 states with energy efficiency resource standards in two groups. We chose one set from "Established Saver" states—those with strong, lengthy track records of energy efficiency programs in terms of their cumulative energy savings, total spending on ratepayer-funding utility energy efficiency programs (specifically excluding load management). We selected the other set from "Rapid Start" states—those with recent, rapid increases in spending and budgets, and without a long record of administering and delivering energy efficiency programs. Our selection of states within each group relied on our review of program data and expert judgment. We also strived to achieve geographic diversity to reflect different utility regulatory backgrounds and different energy resource characteristics.

Those interviewed were predominantly utility energy efficiency portfolio and program managers, along with some executives at government agencies and nonprofit organizations with extensive knowledge of utility energy efficiency in their states. We selected people who had perspectives on and experience with EERS policy as well as portfolio and program design approaches and implementation.

Interviews began with one open-ended question, "How will your utility or state reach the increased energy-savings goals?" followed by a series of open-ended prompting questions on specific topics. We supplemented interviews with document review of utility energy efficiency plan filings, impact evaluations, regulatory decisions and orders, and ACEEE and other published research reports.

Respondents were also asked what early results have been, and about their expectations concerning their utility and/or state meeting efficiency resource standards in the future.

STATES EXAMINED IN THIS STUDY

Established Savers

State EERS descriptions are listed in Table 1 chronologically from when the state adopted an EERS. Concerning the inclusion of Connecticut, please note that in 2008 the Connecticut Department of Public Utility Control (DPUC) ordered that the joint 2010 efficiency plan establish broader, longer-term goals,[3] however, Connecticut utilities did not include long-term goals in their joint 2010 or 2011 Plans. Goals for programs do exceed 1% annual savings in 2010 and 2011.

[3] See http://www.aceee.org/sector/state-policy/connecticut - _ftn1#_ftn1

Table 1. Summaries of Established Savers State EERS Policies

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Massachusetts[4] **2009** **Electric and Natural Gas EERS**	Electric: 1.4% in 2010, 2.0% in 2011; 2.4% in 2012 Natural Gas: 0.63% in 2010, 0.83% in 2011; 1.15% in 2012	Electric: D.P.U. Order 09-116 through 09-120) Natural Gas: D.P.U. Order 09-121 through 09-128
Vermont 2000 Electric Tailored Utility Targets (Efficiency Vermont)	~6.75% cumulative savings from 2009 to 2011	30 V.S.A. § 209; VT PSB Docket 5980; PSB Contract[5]
New York 2008 Electric and Natural Gas EERS	Electric: 15% Cumulative savings by 2015 Natural Gas: ~14.7% Cumulative savings by 2020	Electric: NY PSC Order, Case 07-M-0548 Natural Gas: NY PSC Order, Case 07-M-0748
Minnesota 2007 Electric and Natural Gas EERS	Electric: 1.5% annual savings beginning in 2010 Natural Gas: 0.75% annual savings from 2010-2012; 1.5% annual savings in 2013	Minn. Stat. § 216B.241
Connecticut[6] **2005** **Electric**	~1% annual savings 2008-2011	Public Act 07-242 of 2007
California[7] **2004 and 2009** **Electric and Natural Gas EERS**	Electric: ~1% annual savings through 2020 Natural Gas: 150 gross MMTh by 2012	CPUC Decision 04-09-060; CPUC Decision 08-07-047; CPUC Decision 09-09-047

Rapid Starts

State EERS summaries for Rapid Start states are listed below in Table 2.

[4] The underlying statute, Mass. General Laws c. 25 § 21, requires gas and electric efficiency program administrators to procure "all energy efficiency and demand reduction resources that are cost effective or less expensive than supply."
[5] Goals for 2009 and 2010 were combined. Efficiency Vermont also set goals in previous years in three-year intervals.
[6] Connecticut does not currently have long-term energy efficiency savings goals that can be defined as an EERS. It is included in this report because it has very recent experience with an EERS policy.
[7] California's goals presented as gross savings. A rough estimate of California's goal as net savings can be achieved by converting gross savings to net savings using the 2009 net to gross conversion factor of 61% (CPUC 2011). Net goals are approximately 0.8% annual savings for the period 2010-2013, dropping to 0.55% from 2014-2020. California's evaluation and attribution methods are some of the strictest in the country, however, which partly explains the low net to gross conversion factor.

Table 2. Summaries of Rapid Start State EERS Policies

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Arizona 2009 Electric EERS	2% annual savings beginning in 2014., 22% cumulative savings by 2020	Docket Nos. RE-00000C-09-0427, Decision No. 71436
Illinois 2007 Electric and Natural Gas EERS	Electric: 0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter Natural Gas: 8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019)	S.B. 1918 Public Act 96-0033 § 220 ILCS 5/8-103
Ohio 2008 Electric EERS	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019)	ORC 4928.66 et seq. S.B. 221
Colorado 2007 Electric and Natural Gas Tailored Utility Targets	Electric: PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011 and increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019 Natural Gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue)	Colorado Revised Statutes 40-3.2-101, et seq. ; COPUC Docket No. 08A-518E; Docket 10A-554EG
Michigan 2008 Electric and Natural Gas EERS	Electric: 0.3% annual savings in 2009, ramping up to 1% in 2012 and thereafter Natural Gas: 0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter	M.G.L. ch. 25, § 21; Act 295 of 2008

STRATEGIES FOR INCREASED SAVINGS: ESTABLISHED SAVER STATES

The primary source of information for this section consisted of thirty-two semi-structured interviews with key individuals across the six states, together with review of associated documents from each state. We present the results of the analysis of this information below.

Increased Funding

While states and program administrators employ a variety of strategies to achieve EERS goals, a fundamental prerequisite to obtaining savings on the new order of magnitude is increased investment. All six states in this study with well-established efficiency program administration structures have increased efficiency budgets since the adoption of their EERS policies. The total budget for 2009 electric efficiency programs across these six states was more than double the total annual spending in 2006. For natural gas, the total efficiency budget had more than tripled, as shown in Table 3. During this period, Massachusetts, New York, and Minnesota adopted EERS for the first time. The other states expanded and enhanced their standards. Connecticut passed 'An Act Concerning Electricity and Energy Efficiency.' The California Public Utilities Commission (CPUC) issued a decision setting statewide ten-year goals for the investor-owned utilities. The Vermont legislature voted to pass Act 61 of 2005 to remove the efficiency spending cap, allowing the Public Service Board flexibility to determine appropriate funding levels in the context of minimizing energy costs.

Table 3: Established Savers States Annual Energy Efficiency Expenditures and Budgets 2006-2009

	Electric Spending ($Million)			Budget ($Million)
	2006	**2007**	**2008**	**2009**
California	$357	$755	$1,000	$998
Connecticut	$70	$96	$104	$73[8]
Massachusetts	$125	$120	$125	$184
Minnesota	$48	$91	$138	$111
New York	$225	$242	$236	$378
Vermont	$16	$24	$31	$31
Total	**$840**	**$1,328**	**$1,634**	**$1,776**

	Natural Gas Spending ($Million)			Budget ($Million)
	2006	**2007**	**2008**	**2009**
California	$94.1	$118.1	$220.0	$378.4
Connecticut	$1.4	$2.6	$7.5	$9.4
Massachusetts	$25.6	$25.6	$30.1	$38.0
Minnesota	$15.2	$15.6	$16.2	$22.3
New York	$21.9	$10.6	$50.1	$42.9
Vermont	$1.5	$1.5	$1.9	$1.8
Total	**$159.7**	**$174.0**	**$325.8**	**$492.8**

Source: Molina et al. 2010; Eldridge et al. 2009

Regulatory Policies

Because the regulatory business model throughout the United States is set up on the fundamental principle of shareholder value maximization, almost every investor-owned utility has an incentive to increase retail sales and a disincentive to make a whole-hearted commitment to energy efficiency.

To remove the disincentive, which may be a major barrier to hitting energy-savings targets for the utility, many states have adopted policies decoupling sales volume from revenues. All six of the established saver states reviewed for this report have decoupling authorized for both natural gas and electric utilities. The term "decoupling" refers to the effort to sever the link between utility sales and revenues. In practice, this means that the regulatory body periodically "trues up" any difference between a utility's actual sales for a particular year and sales projections submitted by the utility as part of its revenue requirement.

To create positive motivation for utility management to work more aggressively for deeper energy savings over the long term, states create shareholder incentives that reward utilities for successful implementation of energy efficiency programs. All six of the established saver states reviewed for this report have shareholder incentives authorized for both gas and electric utilities.

California has extensive and well-established state laws and regulations that recognize, prioritize, and promote the value of utility energy efficiency. There is a culture that reinforces the particular policies. These deserve special note even among the top performing states because of the sheer scope, scale, and duration of energy savings achieved. By 2007, California electric utilities had reported cumulative annual energy savings of over 21,000 GWh, more than 30 percent of the total for all 50 states. Two

[8] Decline is due to reallocation of funds for state budget

specific policies that demonstrate the high level of support for sustaining energy savings into the future are:

1.) Loading Order
It is state policy that all cost-effective energy efficiency shall be put in place before making commitment to supply side resources, whether renewable energy or base load power plants. The California Public Utilities Commission takes a strong hand in the resource analysis.

2.) Incentive
The last cycle of the Risk/Reward Incentive Mechanism (RRIM) made up to $450 million potentially available to utilities. The CPUC defined a recent RRIM for investor-owned utilities in the Energy Efficiency Proceeding (CPUC Rulemaking 06-04-010). Decision 07-9-043 (October 2007) establishes a minimum performance standard for the utilities under which incentive earnings accrue only if the IOU energy efficiency portfolio of programs achieves at least 85% of the CPUC's goals. While this incentive mechanism is no longer in effect, a new mechanism is being negotiated.

Non-Utility Energy Savings

Increased funding for utility programs makes the expansion and reinvention of utility efficiency portfolios possible—and therefore, makes reaching stepped-up energy savings requirements placed on the utilities attainable—but not all EERSs rely solely on utility demand-side efficiency programs. In some states, savings from other policies and programs are allowed to contribute toward the total EERS savings goals.

These complementary policies can be significant sources of energy savings that count toward efficiency resource standards Building codes and appliance standards are one large extra-utility wedge of savings that policy makers in a couple of states have added in to meet multi-year and longer term resource needs. For example, the California utilities are eligible to receive credit toward their energy savings goals for their role in advancing state codes and standards. The California Public Utilities Commission has adopted a methodology to assign savings to the utilities for adopted codes and standards called Codes and Standards Enhancements (CASE) (CEC 2009). The Massachusetts utilities are in the process of developing a comprehensive building energy codes support strategy and implementation plan, for which they hope to receive savings credits from the regulators.

In New York, the State Energy Planning Board has projected that almost one-third of the electricity savings in the state's '15 by 15' goal (15 percent reduction in electricity use by the year 2015) will be attributable to codes and standards. Approximately another third will be saved by state agencies other than the New York State Energy Research and Development Authority (NYSERDA), NYSERDA's previously-approved SBC III programs, and through efficiency improvements to transmission and distribution systems. NYSERDA, the investor-owned utilities, cooperatives, and municipal utilities together make up the remainder.

Minnesota has also constructed their efficiency standard to include a substantial share of savings from sources other than utility demand-side efficiency programs. Of the 1.5% annual electric savings, the Next Generation Energy Act only requires that the first 1% must be met with direct utility program energy efficiency savings. Up to 0.5% may be met by efficiency enhancements to a utility's generation, transmission, and distribution infrastructure, and from other non-traditional energy saving sources, such as efficiency enhancements to their own facilities (on the demand side).

Vermont and Connecticut rely on ratepayer funded utility energy efficiency program savings to fulfill their EERSs.

Collaboratives and Stakeholder Processes

In addition to EERS-supporting policies, many states have set up multi-stakeholder groups and processes to enhance collaboration and coordination, share program ideas and expertise, and smooth the path to achieving state EERS policy goals.

Examples are:

- "1.5% Energy Efficiency Solutions Project" in Minnesota, which was created when the Minnesota Division of Energy Resources (DER) contracted with the Minnesota Environmental Initiative (MEI) to lead a multi-stakeholder process to find ways to achieve the 1.5% goal, focusing on four "policy barrier issue areas": behavioral programs, low income, codes and standards, and utility infrastructure improvements. The Project convened technical working groups on the main issues areas to develop proposed solutions.
- Connecticut has a standing Energy Conservation Management Board (ECMB) established, the members of which are appointed by the Department of Public Utility Control (DPUC), that oversees the utilities' efficiency planning and plays a coordinating role.
- Massachusetts' analogous group is the Massachusetts Energy Efficiency Advisory Council (MEEAC), an 11 member stakeholder body chaired by the state Department of Energy Resources (DOER). MEEAC works collaboratively with the utilities to develop coordinated energy efficiency plans.
- New York has several large program administrators to coordinate, including three large state agencies, National Grid, and Con Edison, as well as smaller utilities. A New York Power Authority (NYPA) representative described their overall model toward financing efficiency as a partnership with a very collaborative style, in which they meet frequently with the NYSERDA and the utilities in a "constant effort to reduce market confusion and coordinate [funding sources] [Energy Efficiency Portfolio Standard] EEPS, [Regional Greenhouse Gas Initiative] RGGI, and [American Reinvestment and Recovery Act] ARRA." Additionally, in December 2010, the Public Service Commission established an Implementation Advisory Group (IAG) consisting of Department of Public Service staff and representatives of all the EEPS program administrators. The IAG meets regularly to advise on implementation issues and assist in program coordination among PAs.

Technologies and End Uses

Lighting was the end use category most often cited by respondents as expected to have the greatest impact on achieving future savings goals. CFLs were the technology most often cited.

Efficiency Vermont's Efficient Products Program, with a large share from lighting, made up a quarter of the total energy savings in their portfolio. With high CFL saturation, they are moving toward dimmable, 3-way and specialty CFLs and LED's. From 2009 to 2010, resources were shifted to increase specialty bulbs from 10 to 20 percent of budget.

An approach garnering substantial energy savings in Vermont is the use of lighting designers to decrease lighting density in the commercial sector. Efficiency Vermont has built strong relationships with lighting designers, who can help customers save money that in turn helps to pay for their lighting design audits. Similar dynamics are at work in New York and Connecticut. Electric utilities see the rolling improvement of efficient lighting technologies as creating substantial energy savings opportunities. One utility called the opportunities "almost endless". With the evolution of program management and delivery, Connecticut's United Illuminating could meet their savings goals with lighting alone.

Starting in 2012, the Energy Independence and Security Act (EISA) will begin raising the minimum energy efficiency allowed for light bulbs. As these federal lighting standards go into effect, it will reduce the marginal savings attributable to CFL program. Therefore, as specialty CFLs make up a greater share of savings, and as lighting markets are increasingly transformed—leading to lower attributed savings for the utility—the search is on for the "next CFL" as a large, cost-effective efficiency opportunity. No one interviewed for this report held the position that the void would be filled by one single technology in isolation; instead, an array of partial solutions are likely to be employed.

One view expressed was that standards related to T-12s and T-8s and ballasts are likely to have a far greater marginal efficiency and program impact than CFLs; however, T-8 and T-12 standards were mentioned less often than CFLs were by those we interviewed for this report.

"Deeper, Then Broader"

Instead of substituting another end use for lighting or a different technology to take the place of CFLs, program administrators are redesigning programs to reduce administrative costs per unit of energy saved and reduce lost efficiency opportunities by capturing savings beyond the "low hanging fruit." ("Lost efficiency opportunities" here means potential energy savings not acquired, which in the future will be cost prohibitive when standing on their own.) The approach pervasive in Massachusetts begins with getting "deep" savings per project, achieving high percentage reductions in energy use by acquiring all efficiency that is cost effective when measured as a package. Then as program participation is expanded, total savings multiply. The alternative—of concentrating on the most cost-effective measures only for each customer in the early years—leaves nothing but the most costly measures for the future when EERS savings requirements will be even higher.

The "deeper, then broader" idea is implicit in the way efficiency is done in Vermont, where it allows Efficiency Vermont to allocate funds where they can buy the most long-term energy savings with each dollar. Relative to other program administrators, they do more custom projects, and they are not limited to working with prescriptive measures and prescriptive projects. This allows incentives to be entirely negotiated with the customer, effectively buying down the cost of the project or measure until it becomes an attractive investment for them.

In New York, NYSERDA's commercial and industrial programs mainly aim toward systems approaches and performance-based programs, rather than device- or rebate-focused approaches.

In Connecticut, bundling lighting measures with less cost-effective measures to get deeper savings per project is a program strategy that the utilities are using in all sectors. For residential, they are using a whole house, fuel-blind approach, featuring instrument-guided weatherization, with gas and electric utilities collaborating under the Home Energy Solutions brand.

In the California 2010-2012 program cycle, for the residential sector, the investor-owned utilities (IOUs) are emphasizing whole house retrofits aimed at reducing the annual energy consumption by 20% through comprehensive retrofits. The IOUs focus on getting the largest savings possible in each particular market. In order to do this, they learn as much as possible about each one through market studies, their account representatives and field engineers. The idea is to create an energy package that works for the customer—using more of the customer's language and less energy efficiency jargon.

Programs for New Technologies/New Customer Market Segments

Another dimension of growth to occur on top of "deeper" and "broader" might be called "wider," or more inclusive and comprehensive. Extending their portfolios, whether by developing new programs to run in addition to existing programs, or by providing rebates and other incentives for added efficiency technologies within existing programs, is a way to gain incremental savings which several established saver states are employing to meet sustained high annual savings goals. Adding new programs to fill niches where there are underserved markets, such as restaurants, or adding new technologies such as LED lighting, open up streams of future savings.

Examples abound of program administrators segmenting markets to target programs to previously underserved customer groups and adding new technologies. In New York, NYSERDA and National Grid have developed a collaborative program for hospitals and the health care sector; Con Edison is similarly working with NYSERDA, NYPA, and the Electric Power Research Institute (EPRI) on a data center partnership. In Connecticut, heat pump water heaters will be offered through the Home Energy Solutions program and commercial and industrial programs will add new incentives for induction lighting and LED lighting. Massachusetts is adding ENERGY STAR televisions. Xcel Energy in Minnesota created the Data Center Efficiency Program, and CenterPoint Energy has segmented their natural gas commercial sector to hone in on five more narrowly defined industries with the best savings opportunities.

Behavioral and customer behavior-based programs are growth areas for the future, according to respondents from California, Minnesota, and Massachusetts. All three are at least running pilot behavioral programs. However, none are relying on behavioral programs for substantial savings to meet EERS targets in their plans for the next few years.

Promoting Participation: Upstream Rebates, More Rebates and Enhanced Advertising

Program administrators continue to enhance and extend traditional program approaches to motivate more utility customers to save more energy through their efficiency programs. They are doing more advertising, finding ways to make participation easier and more convenient, and offer higher rebates to more customers.

"Upstream" and "midstream" rebates have been increasingly replacing point-of-purchase rebates at retail for efficient products such as CFLs and appliances. Instead of point-of-purchase rebates for the customers, these rebates are to the manufacturers, retailers, and distributors. This enables them to lower prices and enhance merchandising and promotion. Connecticut's electric utilities have made this change and now do upstream promotions for appliances and lighting. CFLs are discounted at the wholesale level in Massachusetts. In Vermont, buying down the price of CFLs has been combined with an effort to work with retailers statewide, so that CFLs are widely available for only $0.99, even at conveniences stores.

The Long Island Power Authority (LIPA), a publicly-owned electric distribution utility, has been expanding their efficiency portfolio at a scale, budget, and pace that makes it comparable on those fronts to an entire Rapid Start state. To ramp up participation, LIPA has shifted their marketing and communications approaches to include video testimonials, more visuals, and YouTube. In the past, customers were notified of available rebates via mailings, tradeshows, bill stuffers, and local papers. Now advertising and marketing are focused on the decision makers—if the customer is a school, for example, the buildings and grounds manager are targeted. Efforts are underway to improve marketing coordination with the trades, because the tradesmen need to both know the efficiency programs and be able to sell them. For example, a local electrician needs to be aware of which rebates are available and how much. NYPA also reports doing marketing that is more aggressive.

As discussed in the section on funding, more and/or higher rebates are available in all twelve states researched for this report. Increased funding for rebates and other customer financial incentives is highly correlated over time with the states' adoption of EERS policies. Minnesota's largest investor-owned gas and electric utilities are planning for higher rebates per measure and more funding for rebates overall as one of their primary strategies. At the other end of the spectrum, Vermont has included only moderate increases in overall funding for customer financial incentives within their current triennial planning cycle. Efficiency Vermont emphasizes long-term planning, relationship building, program implementation flexibility and innovation as means to increase participation instead of increasing rebates. Massachusetts rebate levels are in the middle range among comparable states. Since there is no spending cap, Massachusetts is planning overall funding increases in the hundreds of millions per year as energy savings targets increase steeply over 2011 and 2012. This way, it is less likely that rebate funds will run out with unexpectedly high participation.

Customer Education and Contractor Training

Respondents seldom mentioned either broad customer education programs or contractor training among their primary strategies for increasing and sustaining high levels of energy savings to comply with EERS requirements. Energy savings impacts from education and training are hard to measure, and many states do not give utilities significant credit toward EERS compliance for the energy savings that result from them. The states with the largest efficiency programs have extensive customer education and workforce development and training investment, staffing, and infrastructure, which together play a major supporting role in the long-term efforts to save significant amounts of energy as a system resource. Among the states studied in this report, California and New York invested the most in education and training and acquired the most savings for their EERSs. These states also spent the most on evaluation, measurement, and verification. In California, two of the twelve statewide programs approved as part of the California utilities' 2010-2012 energy efficiency program portfolio that incorporate concepts from the California Long Term Energy Efficiency Strategic Plan are Workforce Education and Training (WET) and Marketing Education and Outreach (ME&O).

Representatives from utilities in other states noted education and training as one component of broader strategic initiatives. For example, in Minnesota, Xcel Energy added a School Education Kits program as one of several new programs added to their portfolio in their 2010-2012 plan filing.

Connecticut's Department of Public Utility Control approved the 2010 joint Conservation and Load Management plan for the state's electric and natural gas utilities, ordering a number of program changes in response, including increased training on code revisions, which the utilities had not originally included in their joint plan proposal.

Market Transformation

When we asked what role market transformation efforts would play in EERS compliance, responses varied. Interpretations of the meaning of the phrase "market transformation," and how it relates to EERS compliance, also varied. Implementation of energy efficiency plans designed to achieve state policy savings goals have long-term market impacts and may lead to transformed markets. The inverse—implementation of market transformation-oriented programs to comply with EERS—was not described as a primary prospective strategy.

The states with the most extensive and long-running efficiency programs place the most emphasis on market transformation. The California Long-Term Energy Efficiency Strategic Plan adopted by the California Public Utilities Commission in 2008 included four Big Bold Energy Efficiency Strategies. Of these, three have transformed markets as their goal: 1) all new residential construction will be zero net energy by 2020, 2) all new commercial construction in California will be zero net energy by 2030, and 3) the Heating Ventilation and Air Conditioning (HVAC) industry and market will be transformed to ensure that its energy performance is optimal for California's climate.

One of the most significant institutional responses to EERSs has been in New York. As the largest program administrator in the state, NYSERDA is re-aligning the administrative structure of their energy efficiency programs and portfolios. They are integrating programs funded and created in response to the EERS order with those existing programs that included Resource Acquisition. NYSERDA has received approval from NYPSC to reorganize Energy Efficiency Portfolio Standard (EEPS) and System Benefits Charge[9] (SBC) III funding and portfolio composition. Effective July 1, 2011, Resource Acquisition programs in the SBC portfolio, and their budgeted funds, will extend for six months and move over to merge into their EEPS counterparts. A second portfolio, Technology and Market Development, will continue to stay within the SBC portfolio, funded with SBC funds. While some energy savings from both areas will contribute to the statewide '15 by 15' goal, this realignment demonstrates the importance of the distinction.

[9] Please note that New York has the SBC *program* and the SBC *collection mechanism*, which includes collections for the SBC, EEPS, and RPS programs.

In Connecticut, as in most states, the utilities currently do not get any credit toward their EERS goals for energy savings achieved through appliance standards, so developing new appliance standards does not help them hit their targets. CL&P does get some savings attribution from a new pilot program, the Business Sustainability Challenge. CL&P holds classes and brings in companies to train them about sustainability and energy efficiency.

In Minnesota, Xcel Energy describes their future efficiency program success as dependent on many factors, the development of methodologies to quantify savings from nontraditional programs and market transformation among them.

Residential and Commercial/Industrial Sector Funding Allocation

While some utilities have changed the allocation of budget funds among residential, commercial and industrial sectors, there are no significant trends across multiple states.

Two states that are expanding established programs have been shifting budget funds among sectors. Efficiency Vermont's Annual Plan for 2011 shows that the planned share of funds budgeted for business efficiency programs will increase from of 66% of spending in 2009 to 70% in 2011. In Connecticut, the allocation of budget dollars from 2007 to 2010 could be roughly described as half of the money goes to Commercial and Industrial sector programs, one third to Residential, and the rest to Administration, Planning and Education. There has been an increase in the Residential share from 34% to 39%.

For the Massachusetts 2010-12 electric joint energy efficiency plan, the allocation of funding among sectors remained constant within a 1% range from year to year: 72% for commercial and industrial, 24% for residential, and 4% for low-income. For New York, none of the respondents volunteered that shifts in sector budget allocations were going to be a major strategy to meet statewide savings goals; however, New York is still testing the market response to these relatively new programs. LIPA stated that most of the growth in savings at Efficiency Long Island was expected to come from business sector programs. Similarly, in Minnesota, Xcel Energy's 2010 Minnesota electric efficiency budget had $28 million for commercial and industrial programs and $8 million for residential, and will continue the emphasis on business as 70% of their retail sales are to business customers.

One exception where there was a larger reallocation of budget dollars was CenterPoint Energy's proposed Minnesota natural gas efficiency budget for 2010-2012, which allocated an increased share of funds to residential sector programs—despite the savings being three times more expensive per unit of energy saved. The industrial natural gas efficiency sector in CenterPoint's service territory is increasingly saturated, and the number of marginally cost-effective efficiency opportunities is declining. The plan increased the budget for residential programs over 35% and the projected energy savings more than 50%.

STRATEGIES FOR INCREASED SAVINGS: RAPID START STATES

Increased Funding

Rapid Start states have expenses that Established Saver states do not. They have to build their program portfolio from the ground up. Hiring, training, and organizing employees and contractors in addition to marketing and advertising to raise awareness, and many other costs, must be incurred before energy savings are realized. Both sets of states multiplied their electric and natural gas efficiency budgets. Table 4 below shows Rapid Start states' budget increases.

Table 4: Rapid Start States Annual Energy Efficiency Expenditures and Budgets, 2006-2010

State (Year EERS Adopted)	Electric Spending ($Million)			Budget ($Million)	
	2006	2007	2008	2009	2010
Arizona (2009)	$16.4	$31.9	$44.6	$49.2	$87.0
Colorado (2007)	$11.0	$15.3	$17.0	$46.7	$64.7
Michigan (2008)	$10.0	$0.0	$1.6	$50.1	$78.0
Ohio (2008)	$28.8	$28.8	$9.7	$18.6	$152.8
Pennsylvania (2008)	$3.8	$4.1	$2.1	$96.9	$110.0
Illinois (2007)	$3.2	$0.8	$8.8	$89.9	$107.4
Total	**$73**	**$81**	**$84**	**$351**	**$600**

State (Year EERS Adopted)	Natural Gas Spending ($Million)			Budget ($Million)	
	2006	2007	2008	2009	2010
Arizona (2009)	$0	$0	$0.9	$4.0	NA*
Colorado (2007)	$2.5	$2.6	$2.4	$13.3	NA
Illinois (2007)	$0	$0	$0.8	$4.1	NA
Michigan (2008)	$0	$0	$12.4	$30.8	NA
Ohio (2008)	$0.5	$2.9	$12.2	$25.5	NA
Pennsylvania (2009)	$0	$0	$5.1	$8.7	NA
Total	**$3**	**$6**	**$34**	**$86**	NA

Sources: Molina et al. 2010; Eldridge et al. 2009; CEE 2009; CEE 2010
*NA = Not Available.

Regulatory Policies

The Rapid Start states had very little in the way of utility energy efficiency programs prior to establishing resource standards, and did not have significant support through policy or utility or government leadership for efficiency programs to become a major energy resource. While all six Big Saver states have some form of revenue decoupling and shareholder or other utility performance incentive, the Rapid Start states are mixed, as shown in Table 5 below.

Table 5: Rapid Start States Decoupling and Incentive Policy Status

State	Electric EERS	Electric Decoupling	Electric Incentive	Gas EERS	Gas Decoupling	Gas Incentive
Arizona	Yes	No	Yes	Yes	NA	No
Colorado	Yes	No	Yes	Yes	Partial/Pilots	Yes
Illinois	Yes	No	No	Yes	Yes	No
Michigan	Yes	Yes	Yes	Yes	Yes	Yes
Ohio	Yes	Yes	Yes	No	No	NA
Pennsylvania	Yes	No	No	No	No	No

Non-Utility Energy Savings

In marked contrast with the policies of several of the largest and most sophisticated states, Rapid Start state EERS policies are structured to acquire almost all the energy savings by administration of ratepayer-funded demand side energy efficiency programs.

In Ohio, the utilities are responsible to meet their proportional shares of the overall statewide retail sales. However, they may include savings from their large industrial ("mercantile") customers in their plans to comply. Michigan's utilities, including municipal and cooperative operators, are the sole contributors to the savings goals. In Illinois, utilities are accountable for 75% of energy savings mandated by the EERS, and the Department of Commerce and Economic Opportunity (IDCEO), which runs programs for government and low- income customers, is accountable for 25%. Colorado has a general statewide multi-year goal, but it does not strictly meet the definition of an energy efficiency resource standard. The Colorado Public Utilities Commission is, however, required to set goals for the utilities.

Collaboratives and Stakeholder Groups

Many of the Rapid Start states established collaboratives to help plan, coordinate, design, and prepare for energy efficiency programs prior to EERSs going into effect. Common early activities involved the evaluation of energy efficiency potentials and research on best practices of successful programs.

The Illinois Energy Efficiency Stakeholder Advisory Group (ILSAG) was established by the Illinois Commerce Commission to review progress toward achieving the electric energy efficiency goals and to strengthen the large-utility efficiency program portfolios (ComEd, Ameren Illinois) and IDCEO's portfolio. Several major environmental and consumer groups meet along with state and utility representatives.

Michigan has a comparable group. In June 2009, under Orders from the Michigan Public Service Commission (MPSC), in cases U-15805 and U-15806, the MPSC staff started a statewide Energy Optimization Collaborative with the mandatory participation of all gas and electric providers. The purpose of the Collaborative is to review and improve Energy Optimization plans to maximize their effectiveness. A variety of other stakeholders were invited to join, and the order stated that energy efficiency experts, equipment installers, and other interested stakeholders should be encouraged to participate.

The structure is different in Ohio, where the Public Utilities Commission of Ohio (PUCO) rules encourage the formation of stakeholder collaboratives, but do not require their formation. Each of the large utilities has an active stakeholder collaborative.

Utility Program Strategies

Technologies and End Uses

Throughout the Rapid Start states, utilities have consistently pursued the most cost-effective and tried-and-true end uses and technologies. Almost without exception, these are lighting and CFLs. For residential programs, CFLs are the dominant technology. For commercial and industrial programs, there are more lighting technologies, each comprising a significant share of savings, yet CFLs continue to be important.

In 2009-2010, the Michigan utilities targeted the "low-hanging fruit," with lighting programs getting the most emphasis. With the aggressive savings increases planned over the next three to four years in Colorado, Xcel Energy's operating subsidiary Public Service Company of Colorado (PSCo) will build on their strong commercial and industrial programs, expanding CFL and commercial lighting.

Illinois' largest electric utility, ComEd, continues to focus heavily on lighting-oriented programs to achieve energy savings and sees lighting efficiency opportunities persisting in the business sector, such as in warehouses and light manufacturing. Both ComEd and Ameren Illinois describe their choice of lighting and CFLs to be at the core of their portfolios as a result of being risk-averse, with the risk-aversion resulting from the regulatory and policy constraints that they confront, such as net-to-gross attribution of savings and measure-level cost-effectiveness tests. While both have been preparing for and developing non-lighting efforts since the first program year, participant interest in lighting continues to predominate.

Duke Energy Ohio will continue to look to lighting for the next several years. As LED lighting is not yet cost effective under Ohio's cost-effectiveness tests, in 2012 Duke may use an early replacement CFL program—to get residential customers to install the bulbs that they have already bought—in order to be able to count the savings toward their EEPS targets. At Dayton Power and Light (DP&L), during the initial phase of the EEPS, they are implementing a series of traditional energy efficiency programs, heavily emphasizing lighting. In their initial seven-year (2008-2015) plan proposal, 75% of residential savings were from CFLs. The majority of energy savings for DP&L, however, are in the commercial and industrial sectors, which include government customers, and these business programs offer prescriptive rebates for over 100 measures.

Utilities in Arizona, Michigan, and Ohio are running behavioral pilot programs, such as residential feedback systems. DTE Energy was the only one to say they have definite plans to scale up their behavioral programs.

"Deeper, Then Broader"

In contrast to designing programs around the "Deeper, Then Broader" principle exemplified in Massachusetts and in other states with the most energy efficiency experience, the majority of large utilities in Rapid Start states have been aiming for the narrower target of first-year energy savings. Compliance with annual EERS requirements during the first planning cycle is the top priority.

An exception is Xcel Energy, which has operations in several states. Xcel's Public Service Company of Colorado has used a bundled approach to acquiring deeper savings with their large industrial customers, which includes energy planning. By combining efficiency measures that are not sufficiently cost-effective on their own with measures that exceed the cost-effectiveness threshold, large projects with large energy savings are done that otherwise would not. Xcel is replicating this in the commercial sector through PSCo of Colorado's Energy Design Assistance Program for large commercial buildings and new office buildings. Savings have increased 50% for a small group of customers. Respondents have shared that one key is that the annual planning process that has been business as usual is being displaced by a systems thinking approach. Rather than looking at measures or even projects discretely within the context of a single program or budget year, energy efficiency is viewed holistically over multiple years, facilities, and processes.

Duke is another major multi-state utility that is an example of the more typical approach for Rapid Start states. Duke Energy Ohio is not currently offering additional incentives to customers for installing multiple measures per project. Instead, they are emphasizing broad participation rather than deep savings per customer, in part, at least, to capture as much lighting savings as possible before federal standards take full effect and have their full impact. This is also partially because cost effectiveness is determined at the measure level in Ohio, so less cost-effective end use technologies, even if they add an increment of savings to a project, may be screened out as not satisfying the cost-effectiveness test.

Programs for New Technologies/New Customer Market Segments

For states that have had comprehensive efficiency portfolios running for many years, adoption of an EERS often means extending the dimensions of utility efficiency portfolios to seek out new increments of energy savings. It means adding rebates and technical assistance to support specific efficiency technologies and end uses not previously part of the portfolio, segmenting markets to match program offerings to the needs of targeted niches, and adding or extending programs to reach un-served market segments.

Utilities in the Rapid Start states are in a different situation when it comes to adding in technologies or reaching new market segments for several reasons:

- Time available to design, gain commission approvals, and roll out programs is short, so speed is an issue.
- There is more untapped cost-effective efficiency potential in the Rapid Start states.
- Without extensive program implementation experience in their service territories, utilities in Rapid Start states face greater uncertainty and have less incentive to innovate—and more constraints on innovation.
- In anticipation of federal lighting standards becoming effective, some electric utilities see a relative advantage in capturing a greater share of their energy savings from lighting in before 2012.

An observed pattern in Rapid Start states' electric utility programs is to focus on lighting as the largest end use category and CFLs as the technology to rely on, along with a comparatively small number of other tried-and-true programs, during the first program year. Program administrators add new technologies and market segments as they build up their implementation capacity, staffing, contractor relationships, and market knowledge.

For example, after Consumers Energy in Michigan had an initial pilot program conducted in a limited area that demonstrated the effectiveness of their Appliance Recycling Program, they successfully rolled it out statewide. In the Colorado residential sector, PSCo has been running pilot programs for air conditioning, including early retrofits for central air conditioning systems, a tune-up program, and high-performance installation. They are also offering more services, such as small business lighting and process efficiency services. Small business lighting programs, where PSCo hires a lighting auditor for the small business owner, have been very successful.

ComEd provides another template for moving beyond lighting. Looking ahead to the fourth year of the Illinois EERS, they are engaging with more commercial and industrial customers of all sizes to pave the way for increasing participation in large custom programs that stimulate implementation of non-lighting technologies such as efficient industrial processes, variable speed drives and HVAC, as the percentage savings available from lighting opportunities diminishes overall.

In Ohio, Dayton Power & Light (DP&L) made only minor changes from the first program year to the second, adding on programs for government facility audits and new construction efficiency rebates. American Electric Power (AEP) is doing more and more market segmentation, such as adding programs targeted to agricultural energy customers and to restaurants.

Promoting Participation: Higher Rebates and Enhanced Advertising

Greater than anticipated consumer demand for efficiency program services has been a frequent first year experience for utilities among the states with the fastest-growing programs. According to a Michigan Public Service Commission representative, Michigan utilities reported high participation and energy savings in commercial programs, which ran out of funding in June 2010, especially commercial lighting. Some of the utilities had to decrease their rebates because they were so popular. In spite of this initial burst of participation, Consumers Energy filed an amended efficiency plan for 2011-2014 which increases residential program rebates to compensate for federal tax credits expiring in 2010.

In Illinois, ComEd's early experience was similar to Michigan's utilities, with pent-up demand for efficiency leading to trimming rebate amounts to conserve funds. This changed in their third program year as project sizes plummeted. In response, ComEd increased incentives for replacement of T-12 bulbs with high performance T-8 bulbs, occupancy sensors, and de-lamping T-12 fixtures from 3-lamp to 2-lamp. They also increased bonuses to contractors for larger projects and took out full-page print advertisements in trade publications to promote programs to contractors.

Other program administrators are using traditional approaches to motivate consumers to save more energy—offering higher rebates, more kinds of rebates and other financial incentives, and advertising and promoting more widely and through additional channels. In Colorado, PSCo has numerous program efforts and enhancements underway to increase energy savings in the near term (one to three years). PSCo increased rebates across many programs from 20-25% of the consumer's incremental cost to 40%, and they now offer rebates for more products.

Pennsylvania's EERS requires electric savings of 1% of sales by the end of the second program year, a goal Ohio plans to reach in their fifth year, and Colorado is scheduled to reach in their seventh year. Consequently, the Philadelphia Electric Company (PECO) has been advertising and doing outreach for their PECO Smart Ideas program by television, radio, billboard, and magazine. They also conduct programs such as community seminars; meet with customers at information tables; are adding measures to their commercial and industrial programs; are providing rebates for energy efficient televisions; and are revising incentive levels. To get more immediate savings, they are reducing investment in new construction and their Whole Home Performance programs, and shifting more funds to CFL programs.

Customer Education

In our survey, broad-based customer awareness and education campaigns conducted by utility program administrators were seldom mentioned. One exception was in Ohio, where Dayton Power & Light (DP&L) has a school-based educational program delivered and facilitated by the Ohio Energy Project called "Be E-3 Smart". The E-3 program provides energy savings that DP&L can get credit for, but the stated intent is to have a broader impact. The Ohio Energy Project implements a similar program for AEP Ohio.

Contractor Training

In contrast to consumer education, contractor training and certification programs were cited more frequently as making greater savings possible. Ameren Illinois, for example, has met their increasing savings goals. They attribute this to a combination of the economic rebound, incentives paid to the community of energy efficiency contractors, and to the success of the Building Performance Institute's (BPI) training in increasing the number of certified contractors eligible to participate in the programs. Previously, there were only nine qualified contractors available over a service territory of 44,000 square miles. In neighboring Michigan, Consumers Energy has staff experienced with the successful program model used in the early 1990's, which featured a focus on training and working with their trade allies. Consumers Energy and their implementation contractors developed a list of trade allies and provided a general training session for them on efficiency programs, which covered how to assist customers in filling out complete applications. In 2009, their HVAC program had very high participation rates. HVAC trade allies were very motivated to participate due to reduced demand for their services due to the recession. – Similarly, Consumers Energy worked closely with trade allies, especially with the lighting and HVAC rebate programs, to provide business customers with efficiency program knowledge to support and leverage their marketing efforts.

Market Transformation

Rapid Start states have programs and portfolios designed with a shorter time horizon in mind than states with decades of utility energy efficiency experience and the resulting institutional knowledge and perspective. One utility respondent from a Rapid Start state summed up the relationships among market transformation, the state EERS, and their programs saying, "The three year goal is our world." Another gave examples of what people might define as elements of a market transformation program including an upstream CFL buy-down, school-based energy education, or providing contractor training on HVAC tune-up. One of the program managers in a Rapid Start state shared that as far as market transformation goes, "the utility can play a role, but we don't get [EERS] credit for it. There has to be attribution for [full] utility involvement. The California IOUs get paid for their codes and standards work. We could work with builders on codes, but we need money."

Because most of our contacts for this section were with specific utilities, the statewide view of how market transformation relates to EERSs was not emphasized. An Illinois' ComEd manager said that "as a program, our flavor is resource acquisition . . . We do some trainings—Energy Center of Wisconsin does 12 to 14 trainings for trade allies: electrical contractors, retrofit contracts, new construction. ComEd can't claim savings from MT [market transformation], so we pay for our market transformation work from our Marketing budget." IDCEO does not get credit, either. Market transformation activities such as training for contractors and technical assistance do not count for any savings.

Residential and Commercial/Industrial Sector Funding Allocation

Rapid Start states as a group are not making major changes in funding allocation among residential, commercial, and industrial sectors. The large Michigan IOUs are typical. Detroit Edison's approved Energy Optimization plan holds the allocation of funds among sectors constant through 2015, at 45% commercial and industrial and 55% residential. Consumers Energy's amended plan for 2011-2014, increases spending, primarily on residential gas side and a little on the electric.

Observations From Leading Industry Experts

As a final source of information for this study, semi-structured interviews were conducted with a group of seven distinguished energy efficiency experts from around the nation. Together, these seven individuals have nearly 200 years of experience in the energy efficiency field, and have worked in or are very familiar with all of the states profiled in this report. The opinions and observations of these experts on a number of key issues are summarized below.[10]

Likelihood of EERS Success

After identifying the leading EERS states that each respondent was most familiar with, and briefly discussing the current situation in those states, respondents were asked for their assessment of the probability (on a zero to 100 scale) that these states would be able to successfully meet their EERS savings goals. Interestingly, with few exceptions, the expectations were very high—typically in the range of 70% to 90%. The few states assessed at 50% or less tended to be states where there had been administrative difficulties and/or where there had been recent changes in political leadership that raised some question about the strength of support for the EERS policy.

This issue of 'political will' was a common theme. One expert working in two of the states with very aggressive EERS requirements phrased it succinctly:

> "I'd rate the likelihood of success from a technical standpoint at 90%. The question is on the political side. Will they follow through and invest the necessary dollars to achieve the savings?"

Most Important Policies to Facilitate EERS Success

Respondents were asked what supporting policies were most important to enable states to meet the higher levels of the EERS requirements. The major observations from our experts are summarized below.

Funding

The most common and nearly universal response was the need to ensure dependable and sufficient funding to get the job done. As one expert put it: "You need a firm commitment and the political will to spend the money necessary." Another expert phrased this in a particularly colorful way:

[10] The experts interviewed in this project are listed in the Acknowledgements. However, in order to protect anonymity and allow these experts to offer candid observations, no opinions or comments are attributed to specific individuals.

> "The goals can't be met without raising public benefits funding, or else you have to use 'magical thinking'—as some propose—to meet goals without more money by lowering incentives, finding more private financing, etc."

Regulatory Mechanisms to Address Utility Motivation

The other most common response was the need to have policies to properly motivate and address the financial concerns of utilities—if one expects them to be cooperative partners in striving to meet the EERS savings goals. Interestingly, there was some divided opinion on whether 'decoupling' to address the concern about sales losses from energy efficiency, or 'shareholder incentives' to provide a positive incentive for achieving energy savings, was the most important policy. At least one expert favored each of those options over the other. But the more common response was that both were needed in order to fully engage utilities in the energy efficiency effort.

One noteworthy nuance to this issue is the need to have incentives not just for meeting the EERS goals, but for exceeding them. As one respondent put it:

> "Utilities need to have a vested financial stake for meeting and exceeding the goals. Need upside financial incentives for the utilities if they are the administrators."

Similarly, another expert pointed to an incentive structure in a particular state that keeps increasing the incentive up to 150% of the goal, noting the value of having "a dynamic that works to push beyond goals".

Regarding the issue of goals, one respondent emphasized the important point that the EERS policy itself needs to set clear, firm and measurable savings requirements for utilities—with consequences—and not just talk about vague future goals.

Rate Design

Another interesting and potentially very important policy area is rate design. As one respondent suggested:

> "May also need to introduce more radical approaches—rate structures/designs—like BC Hydro, which has introduced an increasing block rate. The more you use, the more you pay. As you move to a higher energy use bracket, you pay more. In BC Hydro's case, the rate nearly doubles from the base rate....Might use some kind of customer rating factor to determine applicable rate—highly efficient customers pay a lower rate, inefficient customers pay a higher rate."

Other Types of Energy Policies

A couple of the experts commented that other 'non-utility' related policies could also be helpful. As one noted:

> "Other non-utility supportive policies such as disclosure [of building energy use] and labeling [of both buildings and equipment] can help drive demand for energy efficiency programs. Having state 'climate change' goals can also help."

Finally, several of the respondents opined that beyond specific policies, it was particularly important that policymakers and regulators establish a clear 'tone' and expectation that energy efficiency is important. As one stated:

> "You need a culture and ethos of energy efficiency by the state and the utilities. Need a true commitment by all the key players that energy efficiency is important," and he pointed to the widespread consensus support in California for the "loading order" policy that energy efficiency is the first utility resource.

Most Important Program Design Issues

The experts were also asked what aspects and/or improvements in program design would be most important in enabling states to meet the aggressive new EERS requirements. We received a wide range of responses to this, but there were some common themes.

Comprehensive Approaches

One frequently expressed view was the need to move away from single-measure, prescriptive rebate type programs, and move strongly toward more comprehensive whole-building, "system" based approaches—which can achieve much deeper savings per participant. Some illustrative comments include:

> "We are seeing a need for greater complexity in program delivery....we are moving away from relatively simple, routine prescriptive rebate programs."

> "Technologies are available to achieve deep reductions—but especially with lighting, it goes more towards overall design, not just technological change-outs and upgrades."

> "We have relied on reaching customers and paying for individual technologies, not necessarily targeting entire buildings and systems."

> "We've documented deep savings retrofits (greater than 30% savings), but these tend to be more demonstrations than what's being done routinely at this point through existing programs. We're still at an early stage of development of these advanced programs."

In regard to that concern about a lack of experience with deep retrofits, one interesting suggestion was that, wherever feasible, programs should include an enhanced 'super-efficiency' option for participants, with extra incentives and technical assistance, so that we can start gaining more experience with truly 'deep' energy retrofits.

Multi-Year Plans and Programs

Along with the call for more comprehensive and "deep savings" approaches, several respondents noted the need to shift to a multi-year focus for program design and delivery.

> "We need to accommodate multi-year program designs in order to better serve business customers especially...in order to better fit with their time frames and schedules for considering capital improvements."

In addition, several experts noted the need to adopt a multi-year approach for energy efficiency resource planning and budgeting as well. As one respondent stated:

> "Goals and program plans set on an annual basis lead to a short-term focus, rather than on things that will lead to deeper long-term savings.... Need to ensure that objectives such as market transformation are also incorporated into the plan."

Moreover, another observed:

> "If you have multi-year plans and strategies as a focus, you'll design things differently. Annual plans tend to promote a focus on immediate savings and a dependence on fast-payback measures (i.e., cream-skimming). But that approach tends to make it more difficult to later achieve the more comprehensive, slower payback measures that are necessary in order to achieve 'deep' savings in a building. Having a longer-term perspective allows one to design programs for deep savings from the outset."

Rebates

Several experts commented that we might need larger rebate levels in order to achieve these higher EERS savings levels. It was noted that this logically might be required to move past quick-payback measures and achieve deeper savings in participant buildings, but also that it may be necessary, at least in the short term, to help overcome customer reluctance in the current poor economy.

In addition to program participants, an interesting variant on the rebate issue raised by one expert was the suggestion for additional performance-based incentives for *contractors*—to reward achievement of deeper savings.

Relationships with Customers

Our experts also noted that program incentives needed to not just be bigger, but smarter. In particular, the issue of building better relationships with major customers was emphasized by several respondents.

> "We need to get better working with building owners and understanding them—much more human resource intensive than past efforts. Not just 'dollars for metal,' but emphasize building customer relationships."

Furthermore:

> "For large C&I customers, the most important element for successful programs is having strong account management staff well versed in energy efficiency. The biggest need is for people to be able to communicate with customers effectively....establishing and maintaining trusted relationships is essential."

Specific Measures

In general, our experts did not get to the level of discussing specific measures that will be important in program design to reach EERS targets. One interesting exception was the area of lighting, where a couple of our respondents went out of their way to emphasize that in spite of the impending federal standards, lighting efficiency was going to remain a crucial factor. As one respondent put it:

> "We simply can't achieve the levels of savings without pushing lighting as a primary goal."

The other area mentioned by a couple of our experts was the emerging area of behavioral programs. While much is yet to be learned about whether and how much 'behavioral' strategies can contribute, there is a feeling that there will be value in developing cutting-edge programs in the areas of feedback and other behavior-based interventions.

Biggest Challenges to Meeting EERS Goals

Political Will

The biggest single challenge to meeting the aggressive EERS savings goals identified by our experts was sustaining the political will to provide the necessary funding to operate the energy efficiency programs. In the out years, to reach savings in the neighborhood of 1.5% to 2.0% per year, program funding will have to exceed historical levels by a significant amount. While still modest in comparison to introducing a large new baseload power plant into rates, for example, energy efficiency charges of 4 to 8 mills per kWh may be difficult to sustain politically. As one expert put it:

> "The challenges are not technical and economic [in terms of cost-effectiveness]. We have measures that can accomplish the savings—and more new ones coming all the time. The question is the level of political support and the willingness to spend the money."

As another of our experts observed:

> "The biggest challenge is political. There needs to be a commitment by all the key players that energy efficiency is important."

Financing

A second important challenge respondents noted was the need to develop better 'financing' capability. Even with adequate 'program funding,' in order to achieve deep savings in customer facilities, there will need to be convenient and affordable access to sources of financing. As one of our experts put it:

> "We still need to figure out how to make this financing thing work. And all the recent problems in that industry make this even more difficult—due to the 'risk-averse' climate."

Another noted that for smaller customers:

> "On-bill financing tied to the premise would be very helpful."

Shortage of Skilled and Experienced Staff

One non-monetary "resource" challenge mentioned by several of our experts was the need for more experienced technical staff to deliver energy efficiency programs. One of our experts framed this as follows:

> "We have a lot of new entrants into the field [as a result of these new EERS policies]—lots of young, bright people, but they lack history. We really need training for new employees and entrants to the industry....this is an essential piece."

Another added:

> "Also, utility reps aren't really trained sales staff for energy efficiency; we need to re-train existing staff—and try to hire staff with engineering sales backgrounds."

The Federal Lighting Standards

One significant technical challenge our experts felt might hinder the ability to meet the higher-end EERS goals is the effect of the impending federal lighting standards on the ability to obtain new incremental savings in the lighting area. As one expert noted:

> "A lot of savings have come from CFLs—from 25-50% of total savings. It's uncertain if CFLs will continue to deliver—not sure if we can still count on savings as federal standards become effective. Clearly CFLs won't be providing as much—not sure what will meet the gap."

However, a couple of our experts who have followed the lighting issue closely felt that lighting would still be an important element. As one put it:

> "The federal lighting standards will be some impediment. But some folks are over-reacting to how big of a problem it will be. There should still be substantial lighting savings available (especially as new technologies advance)."

Building Codes

An additional important related challenge noted by several of our experts is the effect of increasingly stringent building codes and standards applied to new construction and major renovation projects. As these policies mandate higher and higher levels of efficiency, it leaves less "room" for energy efficiency "programs" to capture incremental savings in new construction.

One policy approach that has been taken in a few jurisdictions is to allow utilities to claim a portion of the new savings from new building codes—if they helped achieve those new codes. Because of the increasing visibility and importance of that issue, we asked our experts whether such a policy approach would be necessary in order to be able to meet the higher-end EERS requirements (e.g., 2% per year savings).

Interestingly, our sample of experts was nearly evenly divided on that issue, with three feeling the energy efficiency programs can achieve those high savings levels without claiming credit for codes and standards, and four feeling it will be necessary to include some portion of the effects of those policies. Upon further discussion, there was more convergence than divergence in opinion around the importance of this issue. For example, one of the "don't need them" respondents qualified his vote by saying that was only true under the status quo situation. If codes and standards continued to advance, it may be necessary to revisit that conclusion.

Similarly, on a very pragmatic level, one of the 'no' vote experts also noted:

> "It's not technically necessary to claim the effects of codes and standards to reach those high savings levels—a couple of states and utilities have already demonstrated that—but it may become necessary politically."

Overall, there seemed to be a good consensus that (a) codes and standards are very important policies for achieving energy efficiency savings; and (b) the effects of those policies must be carefully considered when thinking about savings to be captured from energy efficiency programs.

Regulatory Technical Issues

Finally, a couple of our experts also cited some regulatory technical issues that can present challenges, such as the choice and stringency of application of certain benefit-cost tests, and how regulators define and enforce aspects such as 'net savings' vs. 'gross savings.' As an example, screening out programs on the basis of the Total Resource Cost (TRC) test can disadvantage programs that require large customer investments in longer-payback energy efficiency improvements....which is increasingly necessary in order to achieve deep energy savings. Similarly, prolonged arguments over things like "free-ridership rates" can impede the path toward the types of large scale, multi-pronged energy efficiency efforts that are going to be necessary. If energy efficiency is going to truly be pursued as a serious, large-scale utility system resource, some of these historical regulatory tendencies regarding energy efficiency programs are going to have to be reformed (e.g., concepts such as the TRC test and 'free-ridership' adjustments are never applied to utility supply-side resources).

Carbon Pricing

One last question we asked our experts about is the issue of carbon costs. Specifically, we asked each respondent the following question: "In terms of reaching and sustaining the higher end EERS targets, how important will it be to establish a price or cost for carbon emissions? (On a 1-10 scale, with 1= no effect and 10 = essential)"

Although most considered it very important, there was some variation. There were two '9s'; one '8 or 9'; one '7'; one '5'; one '0'; and one abstention. Even the highest raters, however, felt that EERS goals *could* be reached without explicit carbon costs, but that having a clear policy that incorporates a cost of carbon would be a great help. Interestingly, several also noted that the effect of a good carbon policy is not just in increasing the cost of fossil fuel energy (thereby further enhancing the cost-effectiveness of energy efficiency), but that policies such as the Regional Greenhouse Gas Initiative in New England can also provide valuable additional revenues to support energy efficiency programs.

Concluding Thoughts from the Expert Interviews

Overall, it is fair to characterize our panel of experts as (a) optimistic about the technical capability of achieving the existing EERS goals in the states; (b) concerned about some of the challenges—especially the issue of sustaining political will to fund the necessary programs; and (c) pragmatic regarding the policy and program design improvements that still need to be made to help ensure that the high-end EERS goals can be consistently achieved.

One of our experts may have summarized things best in noting:

> "There are three key elements needed for EERS success:
> - Strong policies
> - Adequate funding
> - Capable infrastructure "

Early Results and Outlook for Sustaining High Savings Levels

Early Results

ACEEE's concurrent publication, *Energy Efficiency Resource Standards: A Progress Report on State Experience* (Sciortino et al. 2011), systematically reviews the early energy-saving results for every state with an EERS in effect for two or more years, or twenty of the twenty-six EERS states. Aside from covering a broader range of states, the progress report's primary purpose is to track savings levels compared to targets and discuss general trends affecting states' performance. While there is overlap between the two reports, the two may be differentiated by the primary research questions they ask. The progress report asks, "Are states meeting EERS targets?"; this report asks, "How do states intend to meet aggressive targets?". In this section, we include a subset of the findings from the *Progress Report.*

For some of the Established Savers states, it is not an entirely straightforward question whether or not utilities are on track to continue meeting goals over the long term. Rapid Starts have been meeting early year targets. For both groups, most EERSs have been implemented or increased recently. Publication of energy savings data and reports, such as those of the Energy Information Administration in the U.S. Department of Energy, may lag more than one year after the end of the program year. Measurement and reporting protocols and conventions vary from state to state. Figure 3 below is a compilation of state results in 2010.

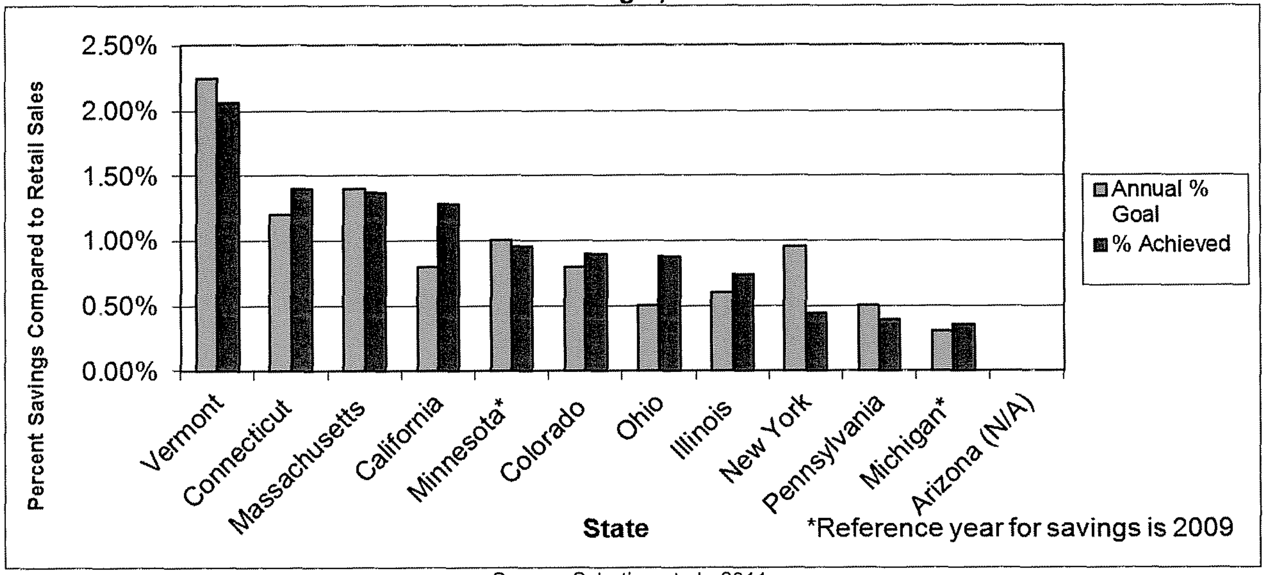
Savings are reported as net annual savings, except for California, which bases current goals and achieved savings on gross annual savings. Saving goals for the California IOU plans must be met over the full 3-year cycle (not annually). Based on non-binding goals for 2010, IOUs are exceeding electricity goals and are close to meeting natural gas goals.[11] The California utilities' evaluated net savings over the three-year 2006-2008 program cycle were much lower, however, and the CPUC report indicated that the utilities fell short of the Commission's adopted goals for that cycle.

California's current EERS policy is embedded in the approved 2010-2012 program portfolios and budgets for the state's IOUs, which call for electricity savings of almost 7,000 GWh, or 3.9% of the IOUs 2008 retail sales, and natural gas savings of approximately 150 MMTh. California IOUs' evaluated net electric savings for the longer period between 2004 and 2008 also fell slightly short of the Commission's adopted goals, achieving 9,442 GWh of savings, or about 1% annually throughout the program period.[12] The utilities plan to make up for these shortfalls in the 2010-2012 program cycle.

[11] Program performance reports to-date for the California investor-owned utilities are posted in a highly usable format at http://eega.cpuc.ca.gov/

[12] Compared to 2008 investor-owned utility retail sales as reported by the Energy Information Administration

Figure 3: Most Recent Year Electric Savings Compared to Goal (or Savings Target)[13]



Source: Sciortino *et al*., 2011.

New York and Minnesota respondents cited the effects of the recession and the overall state of the economy as factors that contributed to their lower savings levels. As shown below in table XX, Minnesota utilities have been increasing electric savings each year, but had not reached the 1% target statewide by the end of 2009. State policy sets an electric target of 1.5% annual savings beginning in 2010, of which 1% must come from utility programs, and up to 0.5% may be from codes, standards, transmission and generation improvements.

Table 6: Minnesota Statewide Electric Savings Achieved from Conservation Improvement Programs, 2006-2009

Year	Statewide Electric Savings Achieved (MWh)	Savings as % of 2007 sales	IOU Natural Gas Savings (MCF)	Savings as % of average sales[14]
2006	411,999	0.60%	N/A	N/A
2007	468,070	0.68%	N/A	N/A
2008	597,288	0.87%	1,534,121	0.54%
2009	648,163	0.95%	1,777,369	0.63%

Source: [MOES 2010]

In New York, NYSERDA and the investor-owned utilities are performing below the EEPS goals, but trends indicate the state is on track to meet its long-term targets. NYSERDA and the IOUs combined to meet 46.8% of their savings goal through 2010 but spent only 35.9% of what was budgeted for programs. Natural gas programs fared somewhat better, achieving 50.9% of the energy savings goal and spending only 40.9% of the total budget through 2010.

[13] California gross savings and targets adjusted to net savings using 61% of conversion factor. California savings include partial savings from advanced codes and standards adopted in the state. California, Iowa, and Washington savings and targets based on IOUs reporting savings as of 2010 only. New York based on NYSERDA and utility program administrators only. Colorado includes only PSCo. Ohio does not include First Energy.

[14] Based on "average sales" figures presented in CIP Energy and Carbon Dioxide Savings Report for 2007-2008.

Table 7: Electric Savings and Spending as percent of targets through 12/31/2010, by Program Administrator

Program Administrator	Percent of Net MWh Target Achieved	Percent of Budget Spent
Central Hudson	31.5%	37.2%
Con Edison	22.4%	24.6%
Niagara Mohawk	50.3%	72.2%
NYSEG	13.1%	20.0%
Orange and Rockland	23.9%	22.4%
Rochester Gas & Electric	27.9%	26.9%
NYSERDA	54.2%	29.9%
NEW YORK STATE	**46.8%**	**35.9%**

Source: NYPSC

Table 8: Natural Gas Savings and Spending as Percent of Targets Through 12/31/2010, by Program Administrator

Program Administrator	Percent of Net Dekatherm Target Achieved	Percent of Budget Spent
Central Hudson	65.4%	74.2%
Con Edison	8.1%	17.4%
Corning	111.2%	106.7%
KED-LI	77.4%	71.1%
KED-NY	28.5%	30.9%
Niagara Mohawk	137.4%	95.0%
NYSEG	127.0%	126.1%
O&R	157.8%	118.0%
RG&E	166.8%	142.6%
St. Lawrence Gas	55.9%	49.8%
NYSERDA	28.0%	25.6%
NEW YORK STATE	**50.9%**	**40.9%**

Source: NYPSC

In Connecticut, energy savings results have been more variable relative to annual standards. As the table below illustrates, the state's programs funded by the Connecticut Energy Efficiency Fund (CEEF) have been near or above the 1% annual savings for three consecutive years, meeting CLM goals in two of the last three.[15] The dip in savings in 2009 was due to a cut in funding to the CEEF. These figures include programs administered by both IOUs and municipal utilities.[16]

[15] Since CHP is included in the Class III targets, comparing energy efficiency savings to the RPS goals would not be accurate. Currently, there is no analysis of progress towards meeting Class III RPS targets.
[16] For most recent information on municipal utilities' performance, see Energy Efficiency Services 2009 Annual Report, Connecticut Municipal Electric Energy Cooperative.

Table 9: Connecticut Statewide Energy Efficiency Savings vs. Goals 2008-2011

	2008		2009		2010		2011	
	Goal	**Actual**	**Goal**	**Actual**	**Goal**	**Actual**	**Goal**	**Actual**
Electric Energy Efficiency Savings (GWh)	250	368	277	237	360	423	325	N/A
As Percent of Sales*	**0.8%**	**1.2%**	**0.94%**	**0.8%**	**1.2%**	**1.4%****	**1.1%**	N/A

Source: 2009, 2010 and 2011 Conservation and Load Management Plans; CL&P et al 2011
Note: Data includes low-income programs
*Based on same year sales
**Based on 2009 Sales

In 2008 Vermont achieved unprecedented savings levels equal to 2.5% of annual sales, exceeding its MWh goal for the 3-year period. In 2007 and 2008, savings from energy efficiency measures more than offset the average underlying rate of electricity load growth. Savings dropped slightly to 1.6% in 2009, but rebounded significantly in 2010 as the state once again exceeded 2% annual savings. Judging performance on an annual basis, Vermont almost met over 90% of its goal in 2010, but at 3.7% savings over two years, it will need to make up for lost ground in order to meet the three year of 6.75% savings by the end of 2011.

Table 10: Efficiency Vermont Energy Efficiency Savings Achieved vs. Targets

2006-2008 Achieved (MWh)	**2006-2008 Goal (MWh)**	**Percent Attained**	**2009 Savings Achieved (MWh)**	***2010* Savings Achieved (MWh)**	**2009-2011 Goal (MWh)**	***Percent* Attained**
311,000	261,700	119%	85,000	114,000	360,000	55%

Sources: Efficiency Vermont, 2009 Annual Report; 2010 Savings Claim; 2011 Annual Plan

According to the fourth quarter report from the Massachusetts Program Administrators in 2010, the state is on track to meet its 2010 electric and natural gas requirements. The preliminary data shows PA's meeting 98% of their MWh goals, 103% of their Therms goals, and spending less than the allotted budget on electric and natural gas programs.[17]

Table 11: Massachusetts Electric Savings Targets and Savings Achieved, 2010-2012

Year	**Savings Target as Percent of Sales**	**Savings Goal (MWh)**	**Electric Savings Achieved (MWh)**	**Percent of Target Achieved**
2010	1.4%	625,004	609,788	98%
2011	2.0%	897,232		
2012	2.4%	1,103,423		
2010-2012	**5.8%**	**2,625,083**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011.

[17] A report with verified savings will be issued in mid- to late-2011.

Table 12: Massachusetts Natural Gas Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (Therms)	Natural Gas Savings Achieved (Therms)	Percent of Target Achieved
2010	0.63%	13,586,666	13,926,865	103%
2011	0.89%	19,087,301		
2012	1.15%	24,687,219		
2010-2012	**2.67%**	**56,368,432**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011.

Rapid Start states are meeting their electric savings targets in the early years. Colorado has exceeded their EERS electric plan savings, led by Xcel Energy's Public Service Company of Colorado. Three out of the four largest IOUs in Ohio are meeting their goals. For the first two program years, Illinois' major IOUs also met the requirements, as did Michigan's. Many Pennsylvania programs were just being rolled out in 2010, yet for some, the program administrators reduced rebate levels due to overwhelming response in order to stay within budget. This suggests that Pennsylvania's experience may be similar to those of Illinois and Michigan. In 2010, Arizona's Tuscon Electric Power (TEP) and Arizona Public Service (APS) reported that they achieved annual energy savings equivalent to 1.1% of retail energy sales. TEP and APS are the two largest electric utilities in Arizona.[18]

In neighboring Colorado, 2009 was the first year that savings goals took effect and the first year in which Public Service Company of Colorado (PSCo), the largest utility in the state, had a complete and comprehensive efficiency plan in place. PSCo's natural gas savings were 308,761 Dth, or 97% of the goal the Commission-approved plan.[19]

Table 13 : Colorado Electric Utility Savings Targets and Results Achieved as % of Sales

Utility	2009 Target	2009 Achieved	2010 Target	2010 Achieved	2011 Target	2020 (Cumulative 2012-2020)
PSCo	0.6%	**0.8%**	0.8%	**0.9%**	0.9%	13.75%
Black Hills Energy	0.53%	**0.23%***	0.76%	N/A	0.80%	

*Program year beginning July 1, 2009 ending June 30, 2010

Leveraging parent company Xcel Energy's years of program delivery experience in Minnesota, PSCo surpassed their planned 2009 and 2010 electricity savings goals, saving 220 GWh at the generator level in 2009 and 253 GWh in 2010.[20] Black Hills Energy (BHE) was less successful in the 2009/2010 program period. BHE notes in its 2009/10 Annual Status Report that it received approval of its programs only a month prior to the July 1st, 2009 start date, which did not give the utility enough time to design and execute programs in time for the 2009 Summer. As a result, savings and spending fell below targets for the year. BHE spent $1.4 million and saved 4,554 MWh—58% and 44% of their respective targets.[21]

In Ohio, according to self-reported data, AEP, Duke Energy, and DP&L exceeded their requirements in 2009 and 2010. First Energy fell far short in 2009 and will report on its 2010 savings in May 2011.[22] Program portfolios for AEP, DP&L, and Duke Energy as a whole were cost-effective in 2010.

[18] SWEEP Regional Energy Efficiency News, http://www.swenergy.org/news/news/default.aspx?Year=2011#331
[19] Docket No. 08A-366EG. 2009 Demand-Side Management Annual Status Report, 4/5/10
[20] Docket No. 08A-366EG. 2009 Savings data from 2009 Demand-Side Management Annual Status Report, 4/5/10; 2010 Savings data from Fourth Quarter Colorado DSM Roundtable Update, 2/15/11.
[21] Black Hills Energy Colorado Electric Annual Status Report Energy Efficiency Programs 2009-2010
[22] PUCO staff has yet to file rulings on the energy efficiency status reports of any utilities, as required, to confirm compliance with benchmarks.

Unable to ramp up programs quickly, FirstEnergy received a waiver from the PUCO allowing it to meet the remainder of its 2009 requirements in future years.[23] Most recently, the PUCO waived annual requirements for FirstEnergy for 2009, 2010, 2011, and 2012. Instead, First Energy will be required to meet a cumulative benchmark by the end of 2012.[24] PUCO ruled that the Portfolio Plan, as filed by FirstEnergy, was not designed to meet the benchmarks in 2010, which PUCO addressed by allowing FirstEnergy to still comply by meeting a cumulative 2012 target (2.3%). FirstEnergy has applied for rehearing regarding whether the plan was designed to achieve 2010 benchmarks, the results of which are pending at the Commission.

Table 14: Ohio Electric Energy Efficiency Performance by Utility in 2009 and 2010

Utility	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
American Electric Power[25]	136,944	**171,000**	125%	228,125	**306,000**	134%
Dayton Power & Light[26]	43,193	**40,442**	94%	71,781	**101,061**	141%
Duke Energy[27]	68,127	**86,402**	127%	109,420	**310,755**	284%
First Energy[28]	166,310	**22,614**	14%	N/A	N/A	N/A
Total	**414,574**	**320,458**	**77%**	**409,326**	**717,816**	**175%**

Each utility has submitted plans to achieve their requirements through at least 2011, detailing program portfolios, budgets, and expected savings. Utilities also submit long-term plans forecasting their ability to meet targets in 2025. Except for Duke Energy, each utility projected savings levels in line with future requirements (Woodrum, Stephens, & Hollingsworth 2010). In its long term forecast report, Duke Energy projected that it would not be able to cost-effectively achieve the long-term 22% requirement, forecasting that it could only meet 14 to 15 percent.[29] After a series of negotiations with stakeholders, however, Duke Energy agreed to a settlement agreement in which it agrees that "it is reasonable for Duke to assume that sufficient, cost-effective energy savings opportunities exist to allow the Company to meet the energy efficiency and demand reduction benchmarks stated in R.C. 4928.66 over the 10-year forecast period." It also states that CHP is a potentially cost-effective option for assisting Duke to meet its resource requirements.

Illinois utilities faced a rush of demand for their energy efficiency programs in the first two years of the EERS. The Department of Commerce and Economic Opportunity's (DCEO), responsible for 25% of the statewide savings, faced different challenges. One was that goals for the first program years were much higher as a percentage than the IOUs (0.6% vs. 0.2%). The DCEO claims numerous factors prevented outright success for its public sector and low-income programs, such as the economic downturn and its effect on government and school budgets.

Table 15 : Illinois Electric Efficiency Savings 2008-2010

Utility	2008-2009 (PY 1) Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2009-2010 (PY 2) Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
ComEd	148,842	**163,717**	110%	315,223	**456,151**	145%
Ameren Illinois	62,808	**89,955**	143%	118,288	**142,995**	121%
DCEO	54,572	**27,285**	50%	110,715	**72,331**	65%

Sources: ComEd Year 1 Evaluation Report; ComEd Year 2 Evaluation Report; Ameren Illinois Year 1 Annual Report; Ameren Illinois Final PY2 Monthly Report September 2010; DCEO Program Year 2 Evaluation

[23] Order, January 7, 2010, Docket 09-1004-EL-EEC, et al.
[24] Order, March 23, 2011, Docket 09-1947-EL-POR, et al.
[25] Savings calculated on a pro-rated basis. 2009: Docket No. 10-0318-EL-EEC; 2010: 11-1299-EL-EEC
[26] Savings calculated on a pro-rated basis. Docket No. 10-0303-EL-POR; 2010: 11-1276-EL-POR
[27] Calculated as incremental savings. 2009: Docket No. 10-0317-EL-EEC (Appendix A); 2010: 11-1311-EL-EEC
[28] Requirements for 2009 through 2012 waived. 2009 savings achieved filed in Docket No. 10-0277-EL-EEC
[29] Duke Long Term Forecast Report 2010

Pennsylvania electric distribution companies (EDCs) officially began implementing programs counting towards their EERS on June 1, 2009. The 2nd quarter report of Program Year (PY) 2 indicates all of Pennsylvania's utilities are achieving significant savings.[30] Through November 2010, utilities had achieved approximately 58% of the 2011 goal, roughly on track to meet the 1% savings goal by June 2011.[31] Results for Program Year 2 have been promising given that in Program Year 1 utilities only achieved approximately 20% of the two-year goal. In the cases of Allegheny, Met-Ed, and Penelec, savings in the 1st quarter of Program Year 2 exceeded all of those of PY 1. Twenty-seven programs began in the 1st quarter of PY 2, compared to 38 initiated in all of PY 1. The presence of a Statewide Evaluator (SWE) has been an extremely positive development for the state's utilities. The SWE provides timely reports that allow utilities to gauge performance and verify savings.

Table 16: Pennsylvania EERS Targets vs. Achieved

Program Administrator	Percent of 2011 Target Achieved end of PY 1	Percent of 2011 Target Achieved end of 2nd Quarter, PY 2	Percent of 2013 Target Achieved to date
Allegheny	1.4%	1.4%	0.5%
Duquesne	19.0%	22.4%	7.5%
Met-Ed	8.2%	37.1%	12.4%
Penelec	8.9%	45.4%	15.1%
Penn Power	11.7%	46.0%	15.3%
PECO	40.0%	113.0%	38.0%
PPL	22.0%	62.0%	21.0%
STATEWIDE*	**19%**	**58%**	**19.3%**

Source: Act 129 Statewide Evaluator Quarterly Report, Program Year One and Second Quarter, Program Year Two
*ACEEE Estimate, not endorsed by PA PUC

Overall, Michigan Energy Optimization (EO) program savings for electric and natural gas achieved 129 percent of the statewide target in 2009. IOUs achieved 130 percent of their savings target, while municipal utilities reached 107 percent of their savings targets and electric cooperatives met 17 percent of their target (MPSC 2011). The Commission recently approved EO plans from Detroit Edison and Consumers Energy in which both utilities plan to exceed electric and natural gas savings targets every year through 2015.[32]

Table 17: Michigan Electric Energy Efficiency Requirements and Savings, 2009-2011

	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2011 Requirement (MWh)
Statewide Electric EO Program Savings	326,056	375,652	129%	502,797	742,451

[30] Pennsylvania has a Statewide Evaluator, which reports on implementation status quarterly. As of the drafting of this report, the latest confirmed savings data comes from Program Year 2 (2010-2011) 2nd Quarter Report.
[31] Through six of the eight quarters given for utilities to meet the 1% goal in 2011, the theoretical "on-track" savings figure would be 66.6%.
[32] DTE: U-15806-EO Amended; MichCon: U-16412 Amended December 2010

Prognosis

Established Savers

Looking forward, the most frequent expectation expressed by those in Established Savers states is that EERS goals will be met in coming years, and that this will be done by extending proven approaches and by pursuing innovations in program design, funding, and delivery.

This is the case in California, New York, Vermont, and Minnesota. The CPUC and the utilities are cautiously optimistic about the utilities meeting the 2010-2012 program savings goals. Achievement of the energy saving goals from the California IOU plans is viewed over the full 3-year cycle, not annually. Most of the IOUs met or were close to meeting estimated savings goals for 2010. The largest program administrators in New York all expect the '15 by 15' statewide goal (15% energy savings by 2015) to be reached, in spite of early results below target. The near-term shortfall in program performance can be attributed to delays in program approval, as well as new program administrators ramping-up programs. However, results show that energy savings with respect to funding spent is ahead of targets. Specifically, as of Dec. 31, 2010, only 37% of the budget for 2009-11 had been spent, while 51% of the net dekatherm target had been acquired, and 47% of the MWh net savings goal had been achieved (NYPSC 2011). The 2009-10 and 2011 budgets and savings targets for each utility were combined by the New York Public Service Commission to give program administrators time to overcome barriers resulting from the program ramp-up.

Vermonters were the most optimistic, looking forward to electricity savings above 2% and approaching 3% into the future.

Minnesotans were the least optimistic of the established savers. Current findings of achievable potential do not support saving 1.5% per year beyond 2015 using traditional programs and current technologies, even with up to 75% rebate levels. Xcel Energy, who runs the largest electric utility in the state, will strive to meet the electric 1.5% goal over the long term, possibly during the next triennial planning period from 2013 to 2015.

In Massachusetts and Connecticut, predictions of future savings hinged in large part on how much and how consistently program funding will be available in years to come. Program Administrators will be looking to private investors, possibly federal carbon revenue, and to bringing in banks and local credit unions to expand lending for energy efficiency at zero interest or very low interest.

Rapid Starts

The highest expectations for sustained savings were from respondents in Michigan and Pennsylvania. Detroit Edison and MichCon both expect to be—and have MPSC-approved Energy Optimization Plans for—exceeding EEPS savings levels every year through 2015. Consumers Energy says they will be able to sustain savings levels into the future. They anticipate over the long term that they will need to go to the next tier of higher savings after they get the low hanging fruit.

Pennsylvania utilities could face up to a $20 million fine if savings standards are not met by May 2011 and by May 2013. One representative of a major IOU expressed "absolute 100% confidence" that they will be in compliance.

In Colorado, there is concern that by 2014 or 2015 there may be a gap between the savings targets and what the current portfolio of traditional programs can deliver. Xcel Energy, owner of Public Service Company of Colorado, is trying a number of innovative approaches and pilot projects to prepare for closing that gap.

While the largest IOUs in Illinois have gotten a strong start, all the largest Illinois program administrators agree that when the 2% spending caps are reached, the annual savings goals will not be met. Some believe there will be an effort to raise the spending limits.

The major Ohio utilities with approved efficiency programs in the field have been hitting their targets until now, however, they expressed their views of the future as contingent on many factors. Some of these factors include: the treatment of "Mercantile" customer savings, changes to codes and standards and how utilities may or may not get credit for part of the savings due to them, and possible policy changes to reduce the EERS goals themselves. Mercantile savings are their own category of savings addressed separately in the law. Their regulatory treatment has been a point of controversy.

FINDINGS AND CONCLUSIONS

This report compiles and examines the perspectives of utility program managers and leading industry experts on how states are responding to new EERS policies establishing substantial energy efficiency savings requirements. The project focuses on twelve states with strong EERS requirements—six "Rapid Start" states with little or no prior efficiency activity in the years leading up to the adoption of an EERS, and six "Established Savers" states with extensive, long-running, and comprehensive energy efficiency systems.

As the resource procurement era of energy efficiency enters its tenth year, more than half the states in the United States have enacted energy efficiency resource standards. States have made and are making major changes in energy policy to support the fulfillment of the goals of their energy efficiency resource standards. These legislative and regulatory actions to support EERSs include:

Increasing funding

States have increased funding for natural gas and electric utility energy efficiency programs in sync with stepped-up savings standards by an order of magnitude or more. Many states increased funding from millions to tens of millions per year. California's annual energy efficiency budgets have crossed the $1 billion threshold. For Established Savers, funding for electric efficiency more than doubled from $840 million in 2006 to $1,776 million in 2009. Natural gas efficiency funding almost tripled from $160 million in 2006 to $492 million in 2009. Six Rapid Start states' electric funding exploded from $73 million in 2006 to $351 million for 2009 and $600 million for 2010. Natural gas efficiency funding in those six states increased by an even greater multiple, rising from just $3 million in reported spending in 2006 up to budgets totaling $86 million in 2009.

Enacting and expanding decoupling and shareholder incentives

Established Saver states, many with decades of experience and expertise with energy efficiency portfolios, have learned the importance of regulatory policy for creating the business environment that will move and inspire utility program administrators to save more energy. All six have some form of decoupling and shareholder incentives in place. Utilities with approval for decoupling and shareholder incentives are less prevalent in the Rapid Saver states.

Using approaches beyond utility efficiency programs

Resource standards are not all written to rely solely on utility efficiency programs to achieve their energy savings goals, especially in Established Saver states. Often used in conjunction with, and in addition to, traditional utility energy efficiency programs, other vehicles contribute as well, such as tightening energy use in building codes, raising appliance efficiency standards, and authorizing and encouraging efficiency enhancements to transmission and distribution infrastructure. New York is the leading exemplar of this approach, where the state "15% by 2015" goal will be met by approximately one-third savings resulting from codes and standards and transmission and distribution efficiency improvements. Rapid Start states currently rely primarily on utility savings to meet their EERS targets.

Creating and supporting stakeholder collaboratives

Many states have set up multi-stakeholder groups and processes to enhance collaboration and coordination, share program ideas and expertise, and smooth the path to achieving state EERS policy goals. Across the map, in both groups of states, respondents valued the contributions of both temporary and standing collaboratives and found their participation useful.

The leadership provided by the states policy makers and regulators in these four areas has changed the field that utility program administrators and implementation contractors play on. It has become a fertile environment for the innovation, growth, and development of utility efficiency programs and portfolios that are needed to achieve the aggressive EERS goals. Utility program administrators are responding. Major trends included:

Capturing lighting savings early and adding new, higher-efficiency technologies to efficiency portfolios beyond CFLs

Many respondents expressed that diminishing savings opportunities for CFLs and the expected impact of higher federal lighting efficiency standards was creating pressure to go beyond past practices, especially after 2012. Rapid Start states in particular have planned programs to capture as much savings as possible from lighting in the first few years of their resource standards. Established Savers, with less available efficiency potential and declining attribution of savings to IOU programs, are shifting toward new technologies. In Vermont and Connecticut, they are shifting program resources into specialty CFLs, three-way, and dimmable lamps. California has a major, multi-year strategy to transform the HVAC markets.

Adopting new program design approaches and strategies, including "Deeper, Then Broader"

Massachusetts has led the way among Established Savers with the explicit creation of a long-term strategy to optimize the achievement of statewide savings by designing programs to get deeper savings per project up front. All six states use some variation of this approach. By considering cost-effectiveness at the project level or higher rather than measure-by-measure, bundling quick-payback measures with longer-term ones, and providing rebates for gas and electric measures on the same project, they get deep savings from the start. As EERS increase, programs can go after building program participation and continue to preserve cost-effective opportunities, as they have avoided the temptation for "cream skimming". Rapid Start states have not taken advantage of similar strategies as widely, often under pressure to meet steep increases in savings goals under relatively restrictive cost-effectiveness tests, spending caps, and time constraints.

Starting programs for new technologies and new customer market segments

In Established Saver states in particular, portfolios are getting "wider" as administrators provide rebates and assistance to support an ever-greater array of efficiency technologies. For example, the New York Public Service Commission had approved plans for 99 different programs by the end of 2010. Simultaneously, there is an observed trend to focus programs on specific industry and customer segments, tailoring rebates and services to procure the most savings from niches such as restaurants, data centers, hospitals and hotels. Rapid Starts are also adding new programs, but for different reasons and in response to different market and regulatory forces. For the most part, they are beginning with a smaller number of core programs selected as the lower-risk, higher savings choices.

Promoting participation through upstream rebates, more rebates and enhanced advertising

In Established Saver states, program administrators continue to enhance and extend traditional program approaches to motivate more utility customers to save more energy through their efficiency programs. They are doing more advertising, finding ways to make participation easier and more convenient (especially through upstream and midstream lighting and appliance rebates), and offering higher rebates to more customers. Reaching customers through YouTube, making 99-cent CFLs ubiquitously available—and simply paying more to gain the customer's participation—are now widespread. The reverse has sometimes been the case in Rapid Start states such as Illinois, Michigan, and Pennsylvania, where they have seen a rush of pent-up demand during the first program year, leading programs to cut rebates in order to preserve budget dollars.

The input that we received from efficiency program managers and program administrators had much less emphasis on other areas. With some exceptions, respondents did not mention customer outreach and education, contractor training and certification, or broader long-term efforts at market transformation as primary means to comply with EERS requirements. Most of the energy saved from initiatives in these areas is difficult and expensive to measure, and the utilities do not get full credit toward their savings goals for their efforts. While all are important, even critical, for acquiring savings in the long term, in the context of EERS requirements, program administrators must focus their attention on energy savings they will get credit for.

Observations from Industry Experts

The group of seven energy efficiency experts felt that the states about which they were most knowledgeable would be successful in meeting their EERS savings goals. To the extent that this was not the case, they pointed to administrative difficulties or recent changes in political leadership that raised some question about the strength of support for the EERS policy, not a lack of the cost-effective achievable potential. The level of financial investment was a major variable, whereas the inherent potential of programs to perform and attain the energy savings was not specifically called into question.

When asked about the most important factors to facilitate EERS success, experts agreed that funding and regulatory mechanisms to address utility motivation were primary. Rate design, building energy use disclosure, building and equipment labeling, and having state climate change goals also help drive demand for utility energy efficiency programs. Several industry experts also noted that it was particularly important that government officials establish a clear 'tone' and expectation that energy efficiency is important.

The experts confirmed what utilities reported on the importance of the following program design elements:

- Comprehensive approaches that moved beyond single-measure, prescriptive rebate based programs to acquire deep savings
- Multi-year plans and programs, especially for business customers
- Higher rebate levels
- Building better relationships and improvement understanding of customer needs, especially for large commercial and industrial customers
- Continued emphasis on lighting measures

Experts identified corresponding challenges as well, such as political will, financing, shortage of skilled staff, federal lighting standards, building codes, and technical regulatory issues.

Early Results and Outlook

Early results from the first few years of new or expanded EERSs demonstrate growing successes in procuring ever-greater energy efficiency resources. Programs in Rapid Start states are often exceeding their targets in initial years. Established Savers' results have been less consistent relative to their annual efficiency standards in recent years, especially in those states with the longest-running and most extensive programs. In spite of the magnitude of the challenges, with a few exceptions, from the viewpoints of the states and utilities, the prognosis for hitting EERS targets is good.

REFERENCES

[ACEEE] American Council for an Energy-Efficient Economy. 2011. "State Energy Efficiency Policy Database." www.aceee.org/sector/state-policy. Washington, D.C.: American Council for an Energy-Efficient Economy.

[CEC] California Energy Commission. 2009. *Achieving Cost-Effective Energy Efficiency For California: Second Annual Progress Report.* California Energy Commission. CEC-200-2009-008-SD

[CEE 2010] Consortium for Energy Efficiency. 2010. *State of the Efficiency Program Industry 2009 Expenditures, Impacts & 2010 Budgets.* http://www.cee1.org/ee-pe/2010AIR.php3 Boston, Mass. Consortium for Energy Efficiency.

[CEE 2009] Consortium for Energy Efficiency. 2009. *The State of the Efficiency Program Industry Budgets, Expenditures, and Impacts 2009.* http://www.cee1.org/ee-pe/2010AIR.php3 Boston, Mass. Consortium for Energy Efficiency.

[CL&P] The Connecticut Light and Power Company, The United Illuminating Company, Yankee Gas Services Company Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company. Energy Conservation and Management Board. 2010. *2011 Electric and Natural Gas Conservation and Load Management Plan.* Connecticut Department of Public Utility Control. Docket No. 10-10-03. Docket No. 10-10-04. October 1, 2010. http://www.ctsavesenergy.org/

Eldridge, M., M.Sciortino, L. Furrey, S. Nowak, S. Vaidyanathan, M. Neubauer, N. Kaufman, A. Chittum, and S. Black, ACEEE; C. Sheppard, C. Chamberlin, and A. Jacobson, Humboldt State University; Y. Mugica and D. Bryk, Natural Resources Defense Council (NRDC). 2009. *The 2009 State Energy Efficiency Scorecard.* Washington, D.C. American Council for an Energy-Efficient Economy.

Eldridge, M., M. Neubauer, D. York, S. Vaidyanathan, A. Chittum, and S. Nadel. 2008. *The 2008 State Energy Efficiency Scorecard.* Washington, D.C. American Council for an Energy-Efficient Economy.

Friedrich, K., M. Eldridge, D. York, P. Witte and M. Kushler. 2009. *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs.* Washington, D.C. American Council for an Energy-Efficient Economy.

Kushler, M., S. Nadel, D. York, N. Dietsch, and S. Gander. 2006. "Energy Efficiency Resource Standards: The Next Great Leap Forward?" In *Proceedings of the 2006 ACEEE Summer Study on Efficiency in Buildings.* Washington, D.C.: American Council for an Energy-Efficient Economy.

McKinsey & Company. 2009. *Unlocking Energy Efficiency in the U.S. Economy.* McKinsey and Company. www.mckinsey.com/en/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/~/media/McKinsey/dotcom/client_service/EPNG/PDFs/Unlocking%20energy%20efficiency/US_energy_efficiency_full_report.ashx

[MOES] Minnesota Office of Energy Security. 2010. *2007–2008 Minnesota Conservation Improvement Program Energy And Carbon Dioxide Savings Report* Minnesota Office of Energy Security Pursuant to Minnesota Statutes §216B.241, subd. 1c(g) January 15, 2010

Molina, M., M. Neubauer, M. Sciortino, S. Nowak, S. Vaidyanathan, N. Kaufman, and A. Chittum. 2010. *The 2010 ACEEE State Energy Efficiency Scorecard.* Washington, D.C.: American Council for an Energy-Efficient Economy.

Nadel, S., T. Kubo, and H. Geller. 2000. *State Scorecard on Utility Energy Efficiency Programs in 2000.* Washington, D.C.: American Council for an Energy-Efficient Economy.

National Academy of Sciences. 2010. *Real Prospects for Energy Efficiency in the United States*. Washington, D.C.: The National Academies Press.

[NYPSC] New York Public Service Commission. 2011. *EEPS Program Implementation Status Through the 4th Quarter of 2010, March 2011*. New York: Office of Energy and Environment.

Sciortino, M., S. Nowak, P. Witte, D. York, and M. Kushler. 2011. *Energy Efficiency Resource Standards: A Progress Report on State Experience*. Washington, D.C.: American Council for an Energy-Efficient Economy.

Woodrum, A., P. Stevens, and A. Hollingsworth. 2010. *Energy Standards at Work: Ohio Senate Bill 221 Creates a Cleaner Economy*. Policy Matters Ohio.

York, D. and M. Kushler. 2002. *State Scorecard on Utility and Public Benefits Energy Efficiency Programs: An Update*. Washington, D.C.: American Council for an Energy-Efficient Economy.

______. 2005. *ACEEE's 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State-Level Activity*. Washington, D.C.: American Council for an Energy-Efficient Economy.

CONTACTS

Jon Williams	AEP Ohio
Keith Martin	Ameren Illinois
Ken Woolcut	Ameren Illinois
Jeanne Clinton	California Public Utilities Commission
Simon Baker	California Public Utilities Commission
Zenaida G. Tapawan-Conway	California Public Utilities Commission
Angie Kline	CenterPoint Energy
Erinn Monroe	Commonwealth Edison
George Malek	Commonwealth Edison
Mark Thomson	Consolidated Edison
Teri Van Sumeren	Consumers Energy
Thomas Tatham	Dayton Power and Light
Emmett Romine	DTE Energy
Tim Duff	Duke Ohio
Joyce Kung	Environment Northeast
Dan Sosland	Environment Northeast
David Baker	Illinois DCEO
Dan Zaweski	LIPA
Larry Masland	Massachusetts Department of Energy Resources
Franke Gorke	Massachusetts Executive Office of Energy and Environmental Affairs
Karen Gould	Michigan Public Service Commission
Sheldon Strom	Minnesota Center for Energy and Environment
Carl Nelson	Minnesota Center for Energy and Environment
Carol White	National Grid
Helen Eisenfeld	NYPA
Karen Villeneuve	NYSERDA
Pete Savio	NYSERDA
Peggy Neville	NYSERDA
Jeffrey Haase	Office of Energy Security, Minnesota Department of Commerce
Nolan Moser	Ohio Environmental Council
Duane Larson	Pacific Gas & Electric
Frank J. Jiruska	PECO
Bruce Ceniceros	Sacramento Municipal Utility District
Debbie Kimberly	Salt River Project
Steve Galanter	Southern California Edison
Athena Besa	SoCalGas
George Katsufrakis	SoCalGas
Kevin Shore	SoCalGas
Monica Brett	SWEEP
Denise Richardson Smith	Tucson Electric Power
George Twigg	Vermont Energy Investment Corporation
Blair Hamilton	Vermont Energy Investment Corporation
Karen Rhodes	Xcel Energy
Deb Sundin	Xcel Energy

APPENDIX A: SUMMARY OF STATE EERS POLICIES

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Massachusetts[33] 2009 Electric and Natural Gas EERS	Electric: 1.4% in 2010, 2.0% in 2011; 2.4% in 2012 Natural Gas: 0.63% in 2010, 0.83% in 2011; 1.15% in 2012	Electric: D.P.U. Order 09-116 through 09-120) Natural Gas: D.P.U. Order 09-121 through 09-128
Vermont 2000 Electric Tailored Utility Targets (Efficiency Vermont)	~6.75% cumulative savings from 2009 to 2011	30 V.S.A. § 209; VT PSB Docket 5980; PSB Contract[34]
Arizona 2009 Electric EERS	2% annual savings beginning in 2014., 22% cumulative savings by 2020	Docket Nos. RE-00000C-09-0427, Decision No. 71436
Illinois 2007 Electric and Natural Gas EERS	Electric: 0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter Natural Gas: 8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019)	S.B. 1918 Public Act 96-0033 § 220 ILCS 5/8-103
New York 2008 Electric and Natural Gas EERS	Electric: 15% Cumulative savings by 2015 Natural Gas: ~14.7% Cumulative savings by 2020	Electric: NY PSC Order, Case 07-M-0548 Natural Gas: NY PSC Order, Case 07-M-0748
Minnesota 2007 Electric and Natural Gas EERS	Electric: 1.5% annual savings beginning in 2010 Natural Gas: 0.75% annual savings from 2010-2012; 1.5% annual savings in 2013	Minn. Stat. § 216B.241
Iowa 2009 Electric and Natural Gas Tailored Utility Targets	Electric: Varies by utility from 1-1.5% annually by 2013 Natural Gas: Varies by utility from 0.74-1.2% annually by 2013	Senate Bill 2386 and Iowa Code § 476

[33] The underlying statute, Mass. General Laws c. 25 § 21, requires gas and electric efficiency program administrators to procure "all energy efficiency and demand reduction resources that are cost effective or less expensive than supply."
[34] Goals for 2009 and 2010 were combined. Efficiency Vermont also set goals in previous years in three-year intervals.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Rhode Island 2006 Electric and Natural Gas Tailored Utility Targets	Electric: ~1.3% in 2010; 1.5% in 2011; Council proposed 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014 Natural Gas: ~0.4% of sales in 2011; Council proposed 0.75% in 2012, 1.0% in 2013, and 1.2.% in 2014	R.I.G.L § 39-1-27.7
Ohio 2008 Electric EERS	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019)	ORC 4928.66 et seq. S.B. 221
Indiana 2009 Electric EERS	0.3% annual savings in 2010, increasing to 1.1% in 2014, and leveling at 2% in 2019.	Cause No. 42693, Phase II Order
Maryland 2008 Electric EERS	15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (10% by utilities, 5% achieved independently)	Md. Public Utility Companies Code § 7-211
Maine 2010 Electric and Natural Gas Tailored Utility Targets (Efficiency Maine)	Electricity: Annual energy savings of ~1% in FY2011, ramping up to 1.4% in FY2013. Natural Gas: 130 BBtu annually by FY2013	Efficiency Maine Trust: Triennial Plan
Colorado 2007 Electric and Natural Gas Tailored Utility Targets	Electric: PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011 and increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019 Natural Gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue)	Colorado Revised Statutes 40-3.2-101, et seq.; COPUC Docket No. 08A-518E; Docket 10A-554EG

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Wisconsin 2010 Electric and Natural Gas EERS	Electric: 0.75% in 2011, ramping up to 1.5% in 2014. Natural Gas: 0.5% in 2011, ramping up to 1% in 2013	Order, Docket 5-GF-191
Connecticut[35] 2005 Electric	~1% annual savings 2008-2011	Public Act 07-242 of 2007
California[36] 2004 and 2009 Electric and Natural Gas EERS	Electric: ~1% annual savings through 2020 Natural Gas: 150 gross MMTh by 2012	CPUC Decision 04-09-060; CPUC Decision 08-07-047; CPUC Decision 09-09-047
Washington 2006 Electric EERS	Biennial and Ten-Year Goals vary by utility. Law requires savings targets to be based on the Northwest Power Plan, which estimates potential savings of about 1.5% savings annually through 2030 for Washington utilities.	Ballot Initiative I-937 WAC 480-109 WAC 194-37
Michigan 2008 Electric and Natural Gas EERS	Electric: 0.3% annual savings in 2009, ramping up to 1% in 2012 and thereafter Natural Gas: 0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter	M.G.L. ch. 25, § 21; Act 295 of 2008
Oregon 2010 Electric and Natural Gas Tailored Utility Targets (Energy Trust of Oregon)	Electric targets are equivalent to 0.8% of 2009 electric sales in 2010, ramping up to 1% in 2013 and 2014. Natural Gas: 0.2% of sales in 2010 ramping up to 0.4% in 2014	Energy Trust of Oregon 2009 Strategic Plan
Pennsylvania 2004 and 2008 Electric EERS	3% cumulative savings by 2013	66 Pa C.S. § 2806.1; PUC Order Docket No. M-2008-2069887

[35] Connecticut does not currently have long-term energy efficiency savings goals that can be defined as an EERS. It is included in this report because it has very recent experience with an EERS policy.

[36] California's goals presented as gross savings. A rough estimate of California's goal as net savings can be achieved by converting gross savings to net savings using the 2009 net to gross conversion factor of 61% (CPUC 2011). Net goals are approximately 0.8% annual savings for the period 2010-2013, dropping to 0.55% from 2014-2020. California's evaluation and attribution methods are some of the strictest in the country, however, which partly explains the low net to gross conversion factor.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Arkansas 2010 Electric and Natural Gas EERS	Annual reduction of 0.25% of total electric kilowatt-hour (kWh) sales to 0.75% of total electric kWh sales over the next three years (slightly less for natural gas).	Order No. 17, Docket No. 08-144-U; Order No. 15, Docket No. 08-137-U
New Mexico 2008 Electric EERS	5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020	N.M. Stat. § 62-17-1 et seq.
Nevada 2005 and 2009 Electric RPS–EERS	5% Renewable energy by 2025—energy efficiency may meet a quarter of the standard in any given year, or 6.25% cumulative savings by 2025.	NRS 704.7801 et seq.
Hawaii[37] 2004 and 2009 Electric RPS–EERS and EERS	Renewable Portfolio Standards include 15% electrical energy savings through 2015. Starting in 2015 all electric utility savings will count towards Hawaii's Energy Efficiency Portfolio Standards (EEPS). EEPS long-term goal is 4,300 GWh reduction by 2030, or 30% of sales.	HRS §269-91, 92, 96
North Carolina 2007 Electric RPS–EEERS	Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Investor-owned: 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.	N.C. Gen. Stat. § 62-133.8 04 NCAC 11 R08-64, et seq.
Texas 1999 and 2007 Electric EERS	20% Incremental Load Growth in 2011 (equivalent to ~0.10% annual savings); 25% in 2012, 30% in 2013+	Senate Bill 7; House Bill 3693; Substantive Rule § 25.181
Florida 2009 Electric EERS	3.5% energy savings over 10 years.	Docket Nos. 080407-EG—080413-EG; Order No. PSC-09-0855-FOF-EG
Delaware Pending Electric and Natural Gas EERS	Electricity: 15% electricity cumulative savings by 2015 Natural Gas: 10% cumulative savings by 2015.	SB 106

[37] Although Hawaii does not currently have a mandated annual goal for energy efficiency, ACEEE estimates that the current 30% goal will result in 1.5% annual savings through utility programs.

APPENDIX B: ESTABLISHED SAVERS CASE STUDIES

California

Background

California is a long-time leading state for its utility-sector customer energy efficiency programs, which date back to the 1970s and have grown and evolved substantially over three decades. Its programs and related energy efficiency policies have had a significant impact on per capita electricity use, which has remained essentially constant over the past 30 years.

Investor-owned utilities (IOUs) administer energy efficiency programs with oversight by the California Public Utilities Commission (CPUC), which establishes key policies and guidelines, sets program goals, and approves spending levels. IOUs and third-party contractors implement the programs. A share of public benefits funding is designated to go to non-utility organizations to offer programs that supplement and complement IOU-operated programs.

California's publicly-owned utilities (POUs), such as large municipal utilities serving Los Angeles and Sacramento, voluntarily administer and provide programs to their customers. The CPUC does not have regulatory authority over the POUs. California's utilities fund some of their programs and initiatives through resource procurement budgets and recover their costs through rate cases brought before the CPUC. California's utilities also collect a Public Goods Charge (PGC) on customer utility bills to fund utility energy efficiency programs. Public Goods Charge is California's is a public benefits funding mechanism established in Assembly Bill 1890 in 1996. The PGC on electricity consumption is about 0.48 cents/kWh and covers energy efficiency, renewable energy and R&D. About 0.3 cents of this charge support energy efficiency programs. AB 995, which became law in 2000, extended the electric PGC through January 1, 2012. A natural gas PGC was created by AB 1002 in 1999. It funds cost-effective energy efficiency and other public purpose programs.

For the 2006-2008 efficiency program cycle, California's investor-owned utilities (IOUs) budgeted $2 billion for three years of efficiency programs and reported spending $316 million in 2006, $670 million in 2007, and $932 million in 2008. The POUs collectively spent $104 million on energy efficiency programs in 2008, a 65 percent increase from their 2007 reported expenditures. The Consortium for Energy Efficiency reports 2009 electric utility energy efficiency program budgets totaling $998.3 million and natural gas program budgets of $378.4 million.

On September 18, 2008, with support from the Governor's Office, the California Energy Commission, the California Air Resource Board, the state's utilities, local government, and other key stakeholders, the CPUC adopted the California Long-Term Energy Efficiency Strategic Plan. The Strategic Plan was designed to maximize achievement of cost-effective energy efficiency in California's electricity and natural gas sectors between 2009 and 2020, and beyond. The Plan included four Big Bold Energy Efficiency Strategies: 1) all new residential construction in California will be zero net energy by 2020, 2) all new commercial construction in California will be zero net energy by 2030, 3) the Heating Ventilation and Air Conditioning (HVAC) industry and market will be transformed to ensure that its energy performance is optimal for California's climate and 4) all eligible low–income customers will be given the opportunity to participate in low-income energy efficiency programs by 2020.

On September 24, 2009 the CPUC approved the 2010-2012 portfolios and budgets for the IOUs. Originally the companies filed 2009-2011 portfolios and budgets but due to factors including the adoption of the Strategic Plan and the need for significant revision to the original utility portfolio applications, the Commission delayed the commencement of the program cycle and adopted a bridge funding decision (D.08-10-027) to ensure that programs would continue through 2009. The electricity and natural gas savings goals and budgets for the 2010-2012 IOU portfolios are presented in Table 18.

Table 18: California Goals and Budgets for the 2010-2012 Program Cycle

	PG&E	SCE	SDG&E	SoCal	Total
2010-2012 Program Cycle Electricity Savings (GWh)	3,100	3,316	539	-	6,965
2010-2012 Program Cycle Natural Gas Savings (MMTh)	48.9	-	11.4	90	150.3
2010-2012 Budgets (millions)	$ 1,338	$ 1,228	$ 278	$ 285	$ 3,129

California's Energy Efficiency Resource Standard Policy

Following California's 2001 electricity crisis, the main state resource agencies worked together along with the state's utilities and other key stakeholders and developed the California Integrated Energy Policy Report that included energy savings goals for the state's IOUs. The CPUC formalized the goals in Decision 04-09-060 in September 2004[38]. The goals called for electricity use reductions in 2013 of 23 billion kWh and peak demand reductions of 4.9 million kW from programs operated over the 2004–2013 period. The natural gas goals were set at 67 MMTh per year by 2013. This decision called for the goals to be updated every three years.

In July 2008 (Decision 08-07-047), the CPUC established new targets for energy savings for the years 2012 through 2020 for its regulated utilities[39]. For the nine year period, the gross electricity savings goals were set at 16 billion kWh and over 4.5 million kW. Gross natural gas savings were set at 620 MMTh.

California's 2010-2012 Energy Efficiency Plan sets targets for its four major electric and gas utilities.[40] Over the three year period, the plan calls for electricity savings of almost 1,500 MW of peak savings and 7,000 GWh and natural gas savings of approximately 150 MMTh.

Funding and Policy Approaches to Achieve Increased Savings

A number of regulatory and state policies help the IOUs meet their energy savings goals.

California's Consistent Support for Energy Efficiency

California's consistent and long-term support of energy efficiency has provided an environment that has made it safe for the utilities to invest resources in energy efficiency. Over the last 30 years, the CPUC, the state utilities, state businesses, and other interested stakeholders have made energy efficiency an integral part of the state's energy and business infrastructure.

Energy Efficiency First

Energy efficiency is the first priority in California's loading order for energy resources. This was first acknowledged in California's 2003 Final Energy Action Plan I. Under Public Utilities Code Section 454.5(b)(9)(C), investor owned utilities are required to first meet their unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible.

Program and Budget Flexibility

Program and budget flexibility are important California regulatory policies that contribute to the utilities' success in meeting the energy efficiency savings goals. The utilities are permitted to move funding from

[38] http://www.aceee.org/sector/state-policy/california - ftn1# ftn1
[39] http://www.aceee.org/sector/state-policy/california - ftn4# ftn4
[40] http://www.aceee.org/sector/state-policy/california - ftn8# ftn8

unsuccessful programs to successful programs. The utilities agreed that it would be difficult to meet California's savings goals without this flexibility.

Decoupling

California initially implemented decoupling through the Supply Adjustment Mechanism (SAM) for gas utilities beginning in 1978 (Decision 88835). By 1982, similar mechanisms were in place for the three electric IOUs. As the gas industry restructured, gas utilities began to serve large customers under a straight fixed-variable rate design, which continues through today. The CPUC stopped the electric decoupling mechanisms in 1996 due to restructuring of the electric power industry.

In 2001, the Legislature passed Section 739.10, which required that the CPUC resume decoupling. Decoupling resumed for Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric beginning with the 2004 revenue requirement. Currently, the revenue decoupling program is combined with performance incentives for meeting or exceeding energy efficiency targets. Revenue requirements are adjusted for customer growth, productivity, weather, and inflation on an annual basis with rate cases every three or four years, varying by utility.

Decoupling mechanisms have been developed and applied in individual cases with the IOU utilities. All of the investor-owned electric and gas utilities have decoupling. It is an important policy for California's "big, bold" energy efficiency initiative. There have been no specific evaluations performed of the decoupling mechanisms as of March 2010 (CA Code Sec. 9 Section 739(3) and Sec. 10 Section 739.10 as amended by A.B. XI 29; Decisions 98-03-063 & 07-09-043).

Shareholder Incentives

The CPUC defined a new Risk/Reward Mechanism for investor-owned utilities in the Energy Efficiency Proceeding (CPUC Rulemaking 06-04-010). Decision 07-9-043 (October 2007) established a minimum performance standard for the utilities under which incentive earnings accrued only if the IOU energy efficiency portfolio of programs achieved at least 85 percent of the CPUC's goals. The incentive formula called for utilities to receive 9% of net benefits if they achieved between 85-99% of savings goals, and 12% of net benefits if they met or exceeded savings goals up to the earnings caps established for each utility. Utilities can earn a percentage of their incentive earnings before evaluation procedures verify their impacts.

In addition to getting energy savings credit for traditional energy efficiency programs, the utilities get energy savings credit when higher state energy codes and standards go into effect. This encourages the utilities to fund programs that impact state codes and standards.

Administrative and Program Strategies to Achieve Sustained Energy Savings

Decision 09-09-047 (October 2009) gives an overview of the California utilities' 2010-2012 energy efficiency program portfolio. The portfolio incorporates program concepts developed as part of the California Long Term Energy Efficiency Strategic Plan.

Twelve statewide programs, and 44 statewide sub-programs are implemented consistently (in terms of program design / logic model, and incentive structure) across the four IOU service areas. The goal is to simplify program participation, reduce customer confusion, and reduce cost of administration and oversight. The IOUs share ideas about the programs and benefit from each other's experience. The 12 statewide programs include: Residential, Commercial, Industrial, Agricultural, New Construction, Lighting Market Transformation, Heating, Ventilation, and Air Conditioning (HVAC), Codes and Standards (C&S), Emerging Technologies, Workforce Education and Training (WET), Marketing Education and Outreach (ME&O), and Demand Side Management Coordination and Integration (IDSM).

In the 2010-2012 program cycle, for the residential sector, the IOUs are emphasizing whole house retrofits aimed at reducing the annual energy consumption by 20% through comprehensive retrofits. In the commercial and government sector programs, the IOUs are placing more emphasis on benchmarking, the process of measuring performance by using a specific indicator, such as energy usage data, to compare a building to an industry standard, or comparable building. The commercial/industrial/agricultural programs are piloting "continuous energy improvement" (CEI) efforts. CEI provides comprehensive strategic energy planning and consulting services for large commercial and industrial customers.

For electricity savings, the number one end use is lighting. Lighting programs include some basic energy efficient lighting (compact fluorescents—CFLs) installations but the emphasis is on more advanced lighting solutions. It is uncertain whether this shift will result in higher savings since, in the short term, CFLs are the cheapest savings available. It is possible, however that focus on a more diversified offering of advanced lighting solutions will contribute towards the sustainability of savings from lighting in the future by priming the market for next new technology.

The IOUs make efforts to use the right channel to get to the customers. For example, for larger customers, the utilities rely on their account representatives who work with energy service companies, etc. that align the customers with measures and programs that are best for them. For residential and small business customers, the IOUs depend on retailers, contractors and manufacturers (trade allies) to help them promote energy efficient products and the utility programs. The utilities meet regularly with the account representatives, retailers, contractors and manufactures to share information about the programs and the customers.

The IOUs focus on getting the largest savings possible from each particular market. In order to do this, they learn as much as possible about each market—through market studies, their account representatives and field engineers. The idea is to create an energy package that works for the customer—using more of the customer's language and less energy efficiency jargon.

The IOUs leverage programs with other resources (government, trade allies), whenever possible. In general, the IOUs increased funding for industrial programs during the 2010-2012 cycle because of the available savings potential in that sector. For natural gas savings, the industrial sector is key.

Early Results, Responses, and Outlook

Program performance reports to-date for the California investor-owned utility programs are posted at http://eega.cpuc.ca.gov/. The utilities' evaluated net savings for the 2006-2008 program cycle fell short of the Commission's adopted goals. The utilities plan to make up for these shortfalls in the 2010-2012 program cycle.

The CPUC and the utilities are cautiously optimistic about the utilities meeting the 2010-2012 program savings goals. Saving goals for the California IOU plans must be met over the full 3-year cycle (not annually). It appears, however, that most of the IOUs met or were close to meeting estimated savings goals for 2010. It is likely that, with time, the programs will continue to improve. Also, the utilities can move funding around—from less successful to more successful programs, if necessary.

In April and May 2010, the CPUC held day-long "Knowledge Transfer" meetings with the IOUs and evaluators to discuss policy lessons learned from the 2006-2008 evaluations. These sessions discussed design changes, trade allies and more, with an eye toward making programmatic improvements that would increase the realized savings levels in the long term.

The CPUC and the IOUs are in the process of hammering out short term and long term Program Performance Metrics (PPMs) for each of the statewide program areas. PPMs will provide qualitative and quantitative means of tracking the programs' achievements at one-year and three-year intervals. This process has reinforced program design changes and collaborative planning efforts.

<u>Prognosis</u>

In general, the IOUs plan on continuing to do what they are doing: looking at the programs from a long-term perspective and continuing to build the necessary infrastructure to maintain the programs over time.

In California, the IOUs recognize that the programs must be well-planned and well-organized; the employees, contractors and trade allies must be knowledgeable and trained; and there needs to be a good evaluation process in place that provides feedback on how the programs can be improved.

As the California energy codes and standards improve, it is more difficult for the utilities to meet savings goals. (The current portfolios have benefit-cost ratios of approximately 1.1–1.2—uncomfortably close to 1.0). The utilities, however, with the support of the CPUC and other parties, continue to push forward. Examples of the utilities efforts to increase savings include:

1) funding emerging technologies (for example, SDG&E and SoCalGas are active participants in developing best practices natural gas programs at the Consortium of Energy Efficiency),
2) tracking implementation of audit recommendations over time—looking at what customers are installing and what they aren't installing to figure out what the utility can do to increase implementation of recommendations, and
3) focusing more on behavioral changes (for example, providing feedback mechanisms to the customers on energy consumption. The CPUC is working on how to evaluate these programs so the companies can get credit for them).

References

[ACEEE] American Council for an Energy-Efficient Economy. 2011. State Energy Efficiency Policy Database. http://www.aceee.org/sector/state-policy

California Public Utilities Commission. 2011. *California Energy Efficiency Strategic Plan, 2011Update* http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/

California Public Utilities Commission http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/

California Public Utilities Commission. Rulemaking 01-08-028, Decision 04-09-060(September 23, 2004). Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212.htm

California Public Utilities Commission. Rulemaking 06-04-010, Decision 08-07-047(July 31, 2008). Decision Adopting Interim Energy Efficiency Savings Goals for 2012 through 2020, and Defining Energy Efficiency Savings Goals for 2009 through 2011. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85995.htm#P66_1562

California Public Utilities Commission, Energy Division. 2006-2008 Energy Efficiency Evaluation Report. July 2010. http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/2006-2008+Energy+Efficiency+Evaluation+Report.htm

California Public Utilities Commission, Decision 09-09-047, Decision Approving 2010 to 2012 Energy Efficiency Portfolios and Budgets, in the Application of Southern California Edison Company (U338E) for Approval of its 2009-2011 Energy Efficiency Program Plans and Associated Public Goods Charge (PGC) and Procurement Funding Requests And Related Matters, Application 08-07-021 (Filed July 21, 2008); September 24, 2009; http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/107378.htm

Consumer Power and Conservation Financing Authority, Energy Resources Conservation and Development Commission and the California Public Utilities Commission. *Final 2003, Energy Action Plan 1.* http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

Connecticut

Background

Connecticut utilities have provided energy efficiency programs for their customers since the 1980's. Today, Connecticut is a leader in utility energy efficiency. Electric and natural gas programs are required by statute. Through 2004, Connecticut electric utilities had reported cumulative annual savings of 2,651 GWh[1], the eleventh highest of all states, and the sixth highest as a percent of retail sales. In June 2005, the Connecticut legislature adopted legislation that added "Class III" requirements to the state's renewable portfolio standard (RPS), covering energy efficiency and combined heat and power plants (CHP). Natural gas efficiency programs were required in PA 05-1, An Act Concerning Energy Independence, passed during the June Special Session as House Bill No. 7501, July 21, 2005. Residential natural gas programs began in 2006 and commercial and industrial sector programs began in 2007.

Connecticut's electric distribution companies, natural gas investor-owned utilities, and municipal electric companies all provide portfolios of energy efficiency programs to their customers. Connecticut Light and Power Company (CL&P), owned by Northeast Utilities, is the largest electric distribution and transmission utility, with retail sales over 14,000 GWh annually. United Illuminating Company (UI) is the other major electric investor-owned utility, with retail sales of 3,000 GWh annually. There are three natural gas distribution utilities: Connecticut Natural Gas Corporation, Southern Connecticut Gas Company, and Yankee Gas Services Company.

Funding for utility electric energy efficiency programs reached almost $50 million in 1993, but then participated in the national trend downward to approximately $30 million per year in the late 1990's. Spending remained in the same range during the first few years after 2000, spiking up from $35 million in 2003 to $58 million in 2004.

The Energy Conservation Management Board (ECMB), appointed by the Department of Public Utility Control (DPUC), is responsible for overseeing the natural gas and electric distribution companies' planning. The ECMB administers the Connecticut Energy Efficiency Fund (CEEF), which is primarily supported by monthly charges on customers' bills. CEEF was created in 1999 to address increasing energy demand and rising costs. The utilities administer the energy efficiency programs. The utilities, with the contractors they hire, implement the programs.

Connecticut has had various types of utility performance incentives for demand side management since 1988. The exact mechanism has changed over time. Gas and electric revenues were not decoupled from sales volume prior to the energy efficiency resource standard policy going into effect.

Energy Efficiency Resource Standard Policy

In 2007, the Connecticut legislature enacted Public Act 07-242, An Act Concerning Electricity and Energy Efficiency, placing new energy efficiency requirements on utilities and establishing regulatory mechanisms, such as electric and natural gas decoupling, to support achievement of these goals. While natural gas efficiency is addressed in the statute, Connecticut does not have an EERS for gas.

The Act requires the electric distribution utilities to procure all cost-effective energy efficiency as their first-priority resource. The combination of complementary policies buttresses the savings requirements, making a very strong energy efficiency resource standard. Under the 2005 law Class III requirements, electricity suppliers must meet 1% of their demand through using efficiency and combined heat and power (CHP) by 2007 and 4% by 2010. The cumulative targets increase by 1% per year. Distribution utilities and other power distributors are responsible for meeting the goals. Existing energy efficiency programs (starting in 2006) may be used to help meet the goals. Third-party providers are also authorized to earn savings certificates and sell these to power providers that have Class III obligations. Under the legislation, certificate values can range between $0.01 and $0.031 per kWh of savings.

The 2007 Act strengthened these requirements through enacting complementary policies, including policies allowing energy savings from waste heat recovery to count toward savings goals. These policies support achievement of greater levels of energy efficiency in Connecticut. In its 2008 decision approving the combined 2009 Conservation and Load Management Plan submitted by the states' major utilities and the Energy Conservation Management Board, the DPUC ordered that the 2010 plan establish broader, longer-term goals in Docket 08-10-03. Connecticut utilities did not include long-term goals in the joint 2010 Plan, but goals for programs of 1.5% savings (of total sales) in 2009 and 2010.[41] The 2010 Conservation and Load Management Plan was approved, but the Department expressed concern that long-term goals were not adopted.[4] However, utilities are reluctant to include long-term goals without commitment from the DPUC to increase levels of funding necessary for aggressive long-term energy efficiency goals. The DPUC has shown no indication it will approve additional ratepayer funding for electric programs beyond the current statutorily-mandated ratepayer charge. Recent energy efficiency budget raids described below have fostered uncertainty that limits the utilties' desire to plan out energy efficiency over a long period of time.

Resource needs are first to be met through "all available energy efficiency resources that are cost-effective, reliable and feasible." The act requires electric distribution companies to review the state's energy and capacity resource assessment and develop a comprehensive plan for procurement of energy resources, considering a full array of supply and demand resources. The act requires resource selection and procurement to be done so as to minimize the costs and to maximize consumer benefits consistent with the state's environmental goals. The distribution companies must submit annual assessments of energy and capacity requirements for the next three, five and ten years, as well as plans to "eliminate growth in electric demand" and to achieve other demand-side and environmental objectives. The DPUC has interpreted this mandate with an emphasis on capacity needs, and has not approved funding increases to achieve all cost-effective energy efficiency. (Docket 10-02-07)

The distribution companies must submit biennial assessments of energy and capacity requirements looking forward three, five and ten years, as well as plans to "eliminate growth in electric demand" and to achieve other demand-side and environmental objectives. The Connecticut Energy Advisory Board (CEAB) reviews the plans before they are submitted to the Department of Public Utility Control (DPUC), along with CEAB comments and analysis. In a separate proceeding, the DPUC reviews the annual Conservation and Load Management Plan, which is developed by the utilities with oversight by the Energy Conservation Management Board (ECMB), which is appointed by the DPUC. The ECMB oversees the Connecticut Energy Efficiency Fund (CEEF), which is primarily supported by monthly charges on customers' bills. CEEF was created in 1998 to address increasing energy demand and rising costs. With oversight by the ECMB and its consultants, the utilities administer the energy efficiency programs.

Decoupling

The law requires the Department of Public Utility Control to order the state's electric and natural gas distribution companies to decouple distribution revenues from the volume of natural gas or electricity sales through one or more of three strategies: (1) a mechanism that adjusts actual distribution revenues to equal allowed distribution revenues, (2) rate design changes that increase the amount of revenue recovered through fixed distribution charges, and/or (3) a sales adjustment clause. Currently, United Illuminating uses a full decoupling mechanism, adjusted annually.

Shareholder Incentives

During annual hearings, the Energy Conservation Management Board (ECMB) reviews the past year's results relative to the established goals and determines a performance incentive for the distribution utilities for achieving or exceeding the goals. The incentive, referred to as a "management fee," can be from 1-8% of the program costs before taxes. The threshold for earning the minimum incentive (1%) is 70% of the goal. At 100% of the goal, the incentive would be 5%. At 130% of goals, it would be 8%. Anticipated incentives are built into the annual budgets (Docket 07-10-03)

[41] See Docket 09-10-03, Conservation and Load Management Plan.

Funding and Policy Approaches to Achieve Increased Savings

Within the new framework created by the Electricity and Energy Efficiency Act, including decoupling and incentive policies described above, spending increases have been a major factor enabling and sustaining the attainment of higher energy savings.

The utility energy efficiency programs have the infrastructure and capabilities in place to acquire all cost-effective savings, but now these funding increases have been stopped and in some cases reversed. Program plans—designed by the utilities to meet the explicit legal requirement for all cost effective energy savings—have been approved by ECMB, but funding increases have been blocked at the DPUC. At UI, the efficiency program budget is dropping.

One policy issue at the center of this is the application of cost effectiveness tests: in a state where statute requires the acquisition of "all cost effective energy efficiency," determining the measure makes all the difference. One utility representative described the debate over cost-effectiveness test as a tug-of-war. Using the Total Resource Cost cost effectiveness test indicates that the utility gas and electric programs are highly cost effective. The Commission uses electric system tests, which results in a lower benefit-cost ratio for the programs proposed by the utilities, and, in turn, indicates that fewer programs are needed to meet the standard of all cost-effective energy efficiency.

Overall state budget deficits work against established energy efficiency program funding. Public Act 10-179 will reallocate approximately $19 million from the Conservation and Load Management Fund in 2012 and $27 million annually from 2013 through 2018 to cut the state deficit. These developments reverse a significant upward trend in energy efficiency program investment in Connecticut shown in Table 19 below:

Table 19: Utility Energy Efficiency Funding

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Electric	$35,231	$58,098	*NA*	$69,600	$95,716	$104,152	$73,446	$115,300	
Gas				$1,400	$2,600	$7,500	$9,400		$16,900

Sources: Eldridge et al. 2006; Eldridge et al 2009; Molina et al. 2010; CEE.

Administrative and Program Strategies to Achieve Increased Energy Savings

Both CL&P and UI representatives emphasized the fuel-blind, integrated, and coordinated aspects of program delivery as critical to their success in delivering energy savings. Many efficiency contractors work with multiple utilities, both gas and electric, which reduces overhead costs and leverages the benefits of shared promotions and branding. At CL&P, only a few projects are electric-only or gas-only; both retrofit and new construction are fully integrated with natural gas utility programs. UI customers use a lot of oil, and how to integrate that is a big question for program managers and designers.

Connecticut's Department of Public Utility Control (DPUC) approved the 2010 joint Conservation and Load Management plan for the state's electric and natural gas utilities. The DPUC ordered a number of program changes, including expanding the rebate for high efficiency gas water heaters, creating a financing pilot program for natural gas customers, recalculating certain energy savings based upon updated buildings codes, and increasing training on code revisions. The full decisions are available on the DPUC's Web site.

More recently, the changes listed below to electric and natural gas efficiency programs, begun in 2009 and 2010, were expanded in the 2011-12 statewide Conservation and Load Management Plan submitted jointly by the utilities (CL&P et al. 2011). Program enhancements listed in the report include:

Residential:

- Low income programs were made a part of Home Energy Solutions (HES), enabling consolidated promotion.
- LED lighting has been kept on the table as a potential program offering with ENERGY STAR developing a specification in August 2010.
- A pilot for residential and small business customers providing energy savings reporting and feedback, started in September 2010, will be fully launched for electric in early 2011 and for natural gas later in 2011.
- Heat Pump Water Heaters will be offered through the Home Energy Solutions program.
- ENERGY STAR 2.5 and 3.0 requirements will be implemented in 2011 and 2012 respectively, resulting in deeper savings per home in the Residential New Construction Program.

Commercial and Industrial:

- Induction lighting and LED lighting technology installation will be encouraged by the addition of new incentives intended to stimulate markets and facilitate early replacement of less-efficiency lighting including T-12 fluorescents and High Intensity Discharge (HID).
- New low interest loans to support businesses that replace T-12's and HID systems.
- Changes to the Comprehensive Initiative to get business customers to implement both broader and deeper projects to capture more total savings.
- Shifts to control systems projects designed to get more significant savings within the Energy Opportunities program by aligning them with other parts of the program.

<u>Technology</u>
The primary technology category for energy savings continues to be lighting at both investor-owned utilities. At UI, they replaced T12 lamps with T8 lamps until those efficiency opportunities began to diminish, and then they moved toward relamping metal halide lights with T5 lamps, and now Super T8 lamps. They see the rolling improvement of efficient technologies as creating almost endless energy savings opportunities. With the evolution of program management and delivery, UI could meet savings goals with lighting alone. However, they are using it to raise project cost effectiveness for greater savings per project by packaging lighting with HVAC and other measures with lower benefit-cost ratios.

<u>Sector Portfolio Allocation</u>
The allocation of budget dollars has not changed drastically from 2007 to 2010: half of the money is goes to Commercial and Industrial sector programs, one third in Residential, and the rest to Administration, Planning and Education. There has been an increase in the Residential share from 34% to 39%.

<u>Program Design</u>
Bundling in lighting measures to get deeper savings per project is a program strategy the utilities are using in all sectors. For residential, they are using a whole house, fuel-blind approach, featuring instrument-guided weatherization, with gas and electric utilities collaborating under the Home Energy Solutions brand. This targets rebate dollars to where they can make the most difference saving energy. Connecticut electric utilities have shifted away from point-of-purchase rebates for appliances and now do upstream promotions for appliances and lighting.

CL&P offers an enhanced incentive package to commercial and industrial customers to facilitate deeper savings per project. They will pay business customers up to 40% of installed cost for some measures, and to encourage more measures per project they will pay up to 50% of the cost for the entire project. Similarly, for small businesses that implement refrigeration controls, lighting, and HVAC measures together, the overall project will provide a reasonable financial payback period. CL&P provides a financial bonus if they implement natural gas efficiency measures too.

Early Results, Responses, and Outlook

A major challenge to sustaining high levels of energy savings in Connecticut is inconsistent levels of funding. In 2009, electric efficiency program budgets dropped from $104 million to $73 million, while savings dropped from 354 GWh to 237 GWh. Program administrators explained that unplanned shifts create customer confusion. Some projects are cancelled that had been planned with the expectation of getting funding. The impact for commercial and industrial customers is significant because they need longer project lead times. Even as the budgets rebounded in 2010, businesses face uncertainty about whether the money will be there. Utility program administrators need the flexibility to access funds from the next budget year to support programs that are succeeding beyond expectations—if that money is not there, some of the most effective areas energy savings may be dampened. Legislative and regulatory decisions to restrict and reduce efficiency funding are against the trend in the Northeast, where adjacent states are tripling electric efficiency budgets or more.

Another force working against utilities getting credit for the savings targets has been declining net-to-gross ratios. UI explained that independent program impact evaluation and research into free ridership has shown that realization rates and attribution have been going down. One possible explanation for this is that consumers have been exposed to energy efficiency messages from multiple sources, such as the Governor's advertising campaign, so it is more challenging to attribute all savings to the program activities.

Market Transformation

When asked about market transformation efforts, both IOU representatives spoke about the retail CFL market as their biggest focus. In 2007 and 2008 the number of CFLs sold took off when large retailers changed stocking practices. The perception was that the market had been transformed, but when the economy went into recession there was a drop-off in CFL sales. When efficiency program support of the level of CFL sales declined, sales volume also declined. The utilities have since reinstated their levels of support for CFLs so that they can count the energy savings from the number of lighting sockets. As appliance standards come into effect, utilities have seen a shift in the buying habits of consumers and increased recognition of the ENERGY STAR label. However, the utilities currently do not get any credit for energy savings achieved through appliance standards, so it does not help them hit their targets.

CL&P does get some savings attribution from a new pilot program, the Business Sustainability Challenge. CL&P holds classes and brings in companies to train them about sustainability and energy efficiency. One example is buying printers that use less paper and less energy. While some efficient hardware measures are installed, the emphasis is on changes in behavior. For large businesses, CL&P also works with approved contractors to provide the Process Reengineering for Increased Manufacturing Efficiency (PRIME) program for large industrial manufacturing customers. With funding provided by the Connecticut Energy Efficiency Fund (CEEF), the program provides training in lean manufacturing techniques, enabling businesses to reduce electrical energy use while cutting waste from their operations using a systems approach.

Prognosis

The largest variable for Connecticut is how much funding will go into programs. Funding hinges on political and regulatory policy choices, especially technical interpretations of cost-effectiveness.

The growth of behavior-based programs will be a much smaller factor. While behavioral programs will not make up a high percentage of savings over the next three years, one Connecticut utility efficiency manager explained that as the incremental benefits become smaller, each new generation of efficient technologies provides a smaller increment of energy savings. In this context, energy savings from behavioral programs become significant because they are relatively larger.

References

[ACEEE] American Council for an Energy-Efficient Economy. 2011. http://www.aceee.org/sector/state-policy/connecticut - _ftnref2#_ftnref2. Washington, D.C. American Council for an Energy-Efficient Economy.

[CEE] Consortium for Energy Efficiency. 2010. *State of the Efficiency Program Industry 2009 Expenditures, Impacts & 2010 Budgets.* http://www.cee1.org/ee-pe/2010AIR.php3 Boston, Mass. Consortium for Energy Efficiency.

[CL&P] The Connecticut Light and Power Company, The United Illuminating Company, Yankee Gas Services Company Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company. Energy Conservation and Management Board. 2010. *2011 Electric and Natural Gas Conservation and Load Management Plan.* Connecticut Department of Public Utility Control. Docket No. 10-10-03. Docket No. 10-10-04. October 1, 2010. http://www.ctsavesenergy.org/

Eldridge, M., W. Prindle, D. York, and S. Nadel. 2006. *The State Energy Efficiency Scorecard for 2006.* Washington, D.C. American Council for an Energy-Efficient Economy.

Eldridge, M., M.Sciortino, L. Furrey, S. Nowak, S. Vaidyanathan, M. Neubauer, N. Kaufman, A. Chittum, and S. Black, ACEEE; C. Sheppard, C. Chamberlin, and A. Jacobson, Humboldt State University; Y. Mugica and D. Bryk, Natural Resources Defense Council (NRDC). 2009. *The 2009 State Energy Efficiency Scorecard.* Washington, D.C. American Council for an Energy-Efficient Economy.

Molina, M., M. Neubauer, M. Sciortino, S. Nowak, S. Vaidyanathan, N. Kaufman, and A. Chittum. 2010. *The 2010 ACEEE State Energy Efficiency Scorecard.* Washington, D.C.: American Council for an Energy-Efficient Economy.

Massachusetts

Background

Massachusetts is a leading state for utility energy efficiency programs with a successful implementation record spanning over 30 years and across all customer sectors. By 1993, electric utilities in Massachusetts had saved a cumulative annual 1,619 GWh. From 1996 to 2000, spending on electric energy efficiency programs increased steadily every year, from $72 million to $99 million. The state created an aggressive funding mechanism and required electric distribution companies to provide energy efficiency programs during its restructuring of the industry in 1997. The law governing these programs is Massachusetts General Law, Chapter 25 §19. Natural gas utilities in the state have offered energy efficiency programs to customers since the late 1980s. Prior to the implementation of the Green Communities Act, Massachusetts utilities spent $25.6 million on natural gas efficiency in 2007 saving 8 million therms; electric utilities spent $120 million that year.

The largest electric utilities are National Grid, NSTAR, and Western Massachusetts Electric Company, owned by Northeast Utilities. Major gas utilities include National Grid and Columbia Gas of Massachusetts. There are five electric energy efficiency program administrators and seven gas program administrators. More than 90% of all customers in the state are eligible to be served by these energy efficiency programs.

Massachusetts has a restructured utility industry with competitive generation and retail markets. The distribution companies remain regulated and are required to offer energy efficiency and other demand-side management programs. The distribution utilities administer their own energy efficiency programs with collaborative input and oversight from the state Department of Energy Resources (DOER) and Department of Public Utilities (DPU).

More specifically, DOER describes the program administration model as a two stage process, with the Massachusetts Energy Efficiency Advisory Council (MEEAC) at the center. MEEAC is an 11 member stakeholder body, chaired by DOER, that works collaboratively with the utilities to develop coordinated energy efficiency plans. Three-year plans are submitted to the Department of Public Utilities (DPU) for approval based on cost-effectiveness and the extent to which administrators use competitive procurement for energy efficiency products and services. DOER acts as the Chair to the Counsel and works to oversee the programs on track to meet their energy savings goals. Administrators may modify their plans midyear or annually through a mid-term modifications process.

Massachusetts' Energy Efficiency Resource Standard Policy

The Green Communities Act of 2008 ushered in a new era for greatly expanded efficiency programs by establishing an "efficiency procurement" approach to EERS policies. That is, the Green Communities Act requires electric and natural gas distribution utilities to invest in all cost-effective energy efficiency that is cheaper than supply resources. Starting in the fall of 2009, and triennially thereafter, the distribution utilities are now required to propose a joint, comprehensive, fully funded state-wide 3-year efficiency plan (for 2010-2012) to satisfy the all cost-effective efficiency procurement requirement for input and review by a new diverse stakeholder efficiency council.

This new Massachusetts Energy Efficiency Advisory Council (EEAC) plays a central role in planning and overseeing the utilities' program administration. The EEAC is an 11 member stakeholder body, representing commercial, industrial, residential, low income, labor, and environmental interests, chaired by Massachusetts Department of Energy Resources (DOER), which works collaboratively with the utilities to develop state-wide coordinated energy efficiency plans. After EEAC review and approval, plans are submitted to the Department of Public Utilities (DPU) for analysis and cost-effectiveness testing. The EEAC and DOER help to keep programs on track to meet their energy savings goals. Plans are updated annually and may be modified mid-term. There are five electric energy efficiency program administrators and seven gas program administrators, whose work is overseen by the EEAC and approved by the DPU.

The Green Communities Act requires that electric and gas utilities procure all cost-effective energy efficiency before more expense supply resources, requiring a three year planning cycle. On January 28th, 2010 the DPU approved the first 3-year (2010-2012) electric and gas energy efficiency plans under the Green Communities Act, paving the way for the realization of the goals and efficiency procurement requirement established in the Act. The electric efficiency procurement plan is fully funded and ramps up savings each year, from a starting point of 1.0% in 2009, to 1.4% in 2010, 2.0% in 2011, and then to 2.4% of retail electricity sales in 2012. 2.4% is equivalent to a first year savings of 1,103 GWh in 2012. The energy efficiency investments in 2010-2102 will save 2,625 gigawatt-hours (GWh) of electricity in 2012 (the cumulative annual impact in 2012). The statewide totals are comprised entirely of the individual program administrator savings.[42]

The rate of increase, level, and duration of annual savings place Massachusetts standard as one of the most if not the most ambitious EERSs of any state. With annual electricity savings of 2.4 percent per year going forward from 2012, the Massachusetts programs would achieve cumulative annual energy savings equivalent to 30 percent of retail electricity sales in 2020. Customers will use 23.4% less electricity in 2020 than they were forecasted to use (based on the April 2009 revised ISO-NE CELT forecast). Retail energy use in 2020 will be 12.5% less than what customers used in 2009, thereby reducing customer energy use over the next 11 years. (In visual terms, this will bend the curve of projected demand down.)

The natural gas plan will save 24.7 million therms in 2012, equivalent to 1.15 percent of retail natural gas sales in 2012. The energy efficiency investments in 2010-2102 will save over 57.3 million therms of natural gas in 2012 (the cumulative annual impact in 2012). The lifetime energy savings for the gas three-year plan will be almost 897 million therms.

Each efficiency program must be cost effective with a benefit cost ratio greater than one on both a program and sector basis. While rare, it is possible that an efficiency measure could be part of an approved program and fail to meet the test. Cost effectiveness is measured using a version of the Total Resource Cost (TRC)Every year a annual report is filed with the DPU on annual savings and evaluation findings. Every two years the DPU requires that administrators provide an updated avoided energy supply component study, in which avoided costs are updated through a collaborative study funded for the entire New England region.

[42] D.P.U. Order on Electric Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-116 through D.P.U 09-120)

Funding and Policy Approaches to Achieve Increased Savings

A major input required to make steep increases in energy savings attainable and sustainable will be unprecedented funding increases. According to the State of Massachusetts Department of Energy Resources (DOER), electric utilities budgeted $183.8 million for 2009 electric energy efficiency programs from ratepayer-funded sources, a 46 percent increase over 2008 spending. Sources of funding include the System Benefits Charge on customer bills, an adjusting charge approved by DPU, revenues from the ISO New England (ISONE) Forward Capacity Market, and proceeds from the Regional Greenhouse Gas Initiate (RGGI). The Green Communities Act dedicates 80% of RGGI funds to energy efficiency.

For the 2010-12 electric joint energy efficiency plan, the allocation of funding among sectors remained constant from year to year: 72% for commercial and industrial, 24% for residential, and 4% for low-income.

Decoupling

Massachusetts is currently implementing decoupling for all of its gas and electric utilities pursuant to DPU Docket 07-50-A (July 2008). Gas and electric utilities must now include decoupling proposals as a component of their rate cases. Target revenues are determined on a utility-wide basis, and can be adjusted for inflation or capital spending requirements if necessary. The Massachusetts DPU has approved decoupling plans for National Grid Electric Company (DPU 09-39), Bay State Gas Company (DPU 09-30), National Grid Gas Company (DPU 10-55) and Western Massachusetts Electric Company (DPU 10-70).

Shareholder Incentives

A shareholder incentive currently provides an opportunity for investor-owned utilities, who administer the efficiency programs, to earn up to 5.5% of program costs as an incentive for meeting program goals. The incentive is based on a combination of elements including energy savings, net benefits, and metrics that measure market transformation. The order that approved the incentive is DPU 08-50. The electric and gas utilities have negotiated statewide incentive dollars with the MEEAC. Those funds are allocated to each utility based on goals for dollar value of benefits and of net benefits. This common incentive mechanism is applicable to all of the utilities.

Administrative and Program Strategies to Achieve Increased Energy Savings

To stay on track to get the increased energy savings, Massachusetts recognizes the importance of piloting new programs, services, and delivery mechanisms to achieve the state's ambitious energy efficiency objectives. EEAC has been advocating for this more experimental and innovative approach to environmental, consumer and other stakeholder groups, emphasizing the importance of looking beyond the three year planning cycle and that in the short run not every new program effort will succeed, and that it should be acceptable for some initiatives to fail.

EEAC's overall approach to saving more energy is to "go deeper, then broader": to reduce the creation of lost efficiency opportunities and implementation costs per project by designing programs to capture a greater share of potential savings on each project first, and then to expand participation. In practice, they are doing both simultaneously because reaching the goals over short and the long term will require it.

Massachusetts efficiency leaders in the legislature and agencies including DOER recognized that to reach such aggressive energy savings goals, they would need to take an approach through the EEAC working with the utilities that would be flexible, action-oriented, learning, and adapting. The three-year planning horizon gives everyone involved more certainty about what they are doing. For example, program administrators may need to hire new staff. With a 30-year record of running very effective programs in Massachusetts that have been planned, evaluated, and refined every year, they have been able to create a structure that will obtain and sustain high energy savings. Key elements in the portfolio design are:

1) Expand the existing programs,
2) Integrate electric and gas programs,
3) Remove the funding cap and invest all the resources necessary, and
4) Each customer sector gets the money they pay in for Commercial and Industrial, Residential, and Low Income.

Some individual programs and pilots that have been added include: behavior-based programs, ENERGY STAR televisions, Deep Energy Retrofit, and the Office of the Future in the Commercial sector. All of these are within the rubric of MEEAC's priority of deeper savings per customer before aiming for broader participation. Moreover, DOER has included overarching initiatives, such as US DOE funded building labeling pilot, and the US DOE Save Energy Now industrial program to help in the promotion of energy efficiency improvements.

The relative allocation of spending and savings to each sector and program correspond very closely to the joint three-year plans. There is a standard set of cost-effective measures for all sectors. CFLs are discounted at the wholesale level in Massachusetts, so customers do not need a coupon or get a rebate at point of purchase.

At the request of DOER, the program administrators hired an evaluation consultant to study the amounts of rebates for various measures compared with other states and found that Massachusetts utility efficiency rebates were in the middle of the measured ranges. For residential, 75% of the cost of efficiency measures is available as rebates, up to a limit of $2000. Commercial rebates are often custom, but are in a similar range. For low income customers, who than earn 60% of the median income, energy efficiency is free.

Early Results, Responses, and Outlook

According to the fourth quarter report from the Massachusetts Program Administrators in 2010, the state is on track to meet its 2010 electric and natural gas requirements. The preliminary data shows PA's meeting 98% of their MWh goals, 103% of their Therms goals, and spending less than the allotted budget on electric and natural gas programs.[43]

Table 20: Massachusetts Electric Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (MWh)	Electric Savings Achieved (MWh)	Percent of Target Achieved
2010	1.4%	625,004	609,788	98%
2011	2.0%	897,232		
2012	2.4%	1,103,423		
2010-2012	**5.8%**	**2,625,083**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011.

[43] A report with verified savings will be issued in mid- to late-2011.

Table 21: Massachusetts Natural Gas Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (Therms)	Natural Gas Savings Achieved (Therms)	Percent of Target Achieved
2010	0.63%	13,586,666	13,926,865	103%
2011	0.89%	19,087,301		
2012	1.15%	24,687,219		
2010-2012	**2.67%**	**56,368,432**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011.

The utility program administrators are implementing the strategic principle of accessing deeper savings first with statewide coordination and the active involvement of DOER. Deeper savings begins with planning for increased budgets for rebates and other financial incentives combined with increased one-on-one customer contact. For businesses, program administrators have dedicated account executives. They also bring in outside consultants to help with O&M and retrocommissioning projects. Residential customers get in-person meetings on how they can obtain program benefits.

Two of the areas that have posed a challenge to designing efficiency portfolios that will deliver the increased cost-effective energy savings were described. The first is a split-incentive problem for rental properties. In one to four family residential rental properties it is difficult for program managers to get the landlords interested in energy efficiency projects. The same pattern is evident with tenant businesses. Second, the Green Communities Act is not singularly focused on energy savings as its only purpose. Another area of the law is job creation. Interest groups such as labor unions and small independent contractors are very vocal on this issue. How to comply with the intentions of the policy impacts how to design programs to achieve savings goals.

Summarizing the factors contributing to EERS success through November 2010 in Massachusetts, one DOER representative identified four:

1. Leadership
2. Long term perspective
3. Transparency and stakeholder participation. "We made the critics a part of the process and made them see the benefits for their constituencies."
4. Innovations to address the challenges involved in the customer experience, such as customer bringing contractors into their homes.

Prognosis

The second triennial planning cycle will be beginning with annual savings requirements having increased to 2.4% for electric and 1.15% for natural gas. Efforts to expand existing programs in the first and second year have been tremendous. Respondents observed that it is not clear how program portfolios will exceed 2.4% savings. (Smaller states are planning on it. Vermont has done it; Rhode Island's statewide electricity savings goal will be even higher, at 2.5% per year.) In Massachusetts, one very significant factor to reaching 2.4% and sustaining that level of performance will be to attract additional sources of financing and to maintain greater total funding. Program Administrators will be looking to private investors, possibly federal carbon revenue, and to bring in banks and local credit unions to expand lending for energy efficiency at zero interest or very low interest.

References

Massachusetts Department of Public Utilities. Order D.T.E./D.P.U. 06-45 May 8, 2007.
http://www.env.state.ma.us/dpu/docs/electric/06-45/5807dpuorder.pdf

Massachusetts Department of Public Utilities. Order D.T.E/D.P.U. 06-34. May 8, 2007. http://www.env.state.ma.us/dpu/docs/electric/06-34/5807dpuorder.pdf

NSTAR Electric Company, *2006 Energy Efficiency Annual Report.* http://www.env.state.ma.us/dpu/docs/electric/07-67/73108nst06arp.pdf

Minnesota

Background

Minnesota has a long record of customer energy efficiency programs offered by both investor-owned and publicly-owned utilities. These programs have achieved significant energy savings for well over two decades, without any of the interruption or upheavals that occurred in most other states that restructured their electric utility industries. Prior to the Next Generation Energy Act going into effect fully in 2010, Minnesota utilities were required to spend a percentage of gross operating revenue (0.5% gas, 1.5% electric and 2.0 % for electrics with nuclear power) on energy efficiency programs rather than to achieve a set amount of energy savings.

Regulated electric utilities are required to file integrated resource plans with the Public Utilities Commission (PUC). The plans identify the potential resources the utilities intend to use to meet consumer energy and demand in future years, including significant energy efficiency and conservation savings.

The program administration model centers on the Conservation Improvement Program (CIP).). CIPs are utility-administered programs with regulatory oversight by the Division of Energy Resources (DER), a state agency housed in the Minnesota Department of Commerce and serving as the state energy office. It was formerly known as the Office of Energy Security. Each gas and electric utility proposes their own CIP, which is reviewed and approved by DER. CIPs have been the main vehicle for efficiency efforts in Minnesota since the 1990's. Goals of the CIP system are to promote use of efficiency technologies, reduce energy costs, defer utility capital investments, and reduce pollution and conserve resources. Until recently, most utility efficiency programs were designed to provide rebates and other financial incentives for customers to buy energy-efficient products instead of standard efficiency products.

The largest investor-owned electric utilities are Xcel Energy, operating as Northern States Power; Minnesota Power Company; and Ottertail Power. Xcel has almost half the MWh retail sales in the state, more than three times as much as Minnesota Power Co., and more than the combined sales of the state's 170-plus public- and cooperatively-owned electric utilities. The largest generation and transmission cooperative, Great River Energy, serves 645,000 people through its 28 distribution co-op members. The largest natural gas utilities in Minnesota are CenterPoint Energy, Xcel Energy, and Minnesota Energy Resources Corporation. Together they comprise about 90% of the natural gas consumption in the state.

Nonprofit organizations have contributed to the development and success of energy efficiency programs in collaboration with the state and utilities. The Center for Energy and Environment, for example, has been involved with advocacy, and has provided technical engineering and finance research, assistance and services since 1979.

The DER reported in 2009 that the investor-owned utilities overall had achieved energy savings of 1.0 percent and 0.5 percent, electric and natural gas respectively, of 2007-2008 retail sales. Over those two years, OES reported that the utilities spent a total of $230 million, which yielded savings of more than 1 million MWh of electricity and 3.5 million MCF of natural gas. Funding is provided via tracker accounting , allowing utilities to recover their costs, which are trued-up annually or in the course of a rate case proceeding. . The $111.2 million electric budget for 2009 eclipsed previous years' utility energy efficiency program spending, which had not exceeded $56 million in any year from 1993 to 2006. While some of the smaller electric utilities had saved over 1.5% of retail energy sales on average from 2004 to 2008, Xcel Energy averaged 0.9% during the same period. This is significant because Xcel has over 80% of the annual sales of the investor-owned utilities. Statewide, the total electric savings attributed to utility energy efficiency programs in 2008 was 540,805 MWh, 0.79% of sales.

Decoupling

The Public Utilities Commission (PUC) is authorized by state statute to approve one or more rate-regulated utilities' proposals for rate-decoupling pilots of up to 3 years. In June 2009, the PUC issued an Order adopting criteria and standards for pilot proposals for revenue decoupling (Docket No. E,G-999/CI-08-132, Issue date June 19, 2009). All utilities planned to file non-binding notices of intent about their plans for filing decoupling pilots by June 1, 2010; filings for pilot proposals are due by December 30, 2011. CenterPoint Energy has an approved natural gas decoupling pilot along with inverted block rates on the distribution side, which began in January 2011.

Shareholder Incentives

Utilities may earn performance incentives for energy savings, set such that at 1.5% of retail sales, electric utilities will earn an incentive of $0.09 per kWh saved while gas utilities will earn between $4.50 to $6.50 per thousand cubic feet saved (except for decoupled utilities who are capped at $3/MCF saved). The threshold level of savings is set at the lower of 50% of the utility's average achievements from 2004-2008 or at 0.4% of retail sales. The percentage of net benefits to be awarded to each utility at different energy savings levels is set at the beginning of each year based on approved goals.

Minnesota's Energy Efficiency Resource Standard Policy

All utilities in the state are subject to the energy savings requirements of the Next Generation Energy Act (NGEA), passed by the Minnesota Legislature in 2007 (Minnesota Statutes 2008 § 216B.241). Among its provisions, the Act set energy-saving goals for utilities of 1.5% of retail sales each year, commencing with the first triennial plan period that began January 1, 2010. Of the 1.5%, the first 1% must be met with direct energy efficiency energy savings, or conservation improvements. This may include savings from efficiency measures installed at a utility's own facilities. Up to 0.5% may be met by efficiency enhancements to each utility's generation, transmission, and distribution infrastructure. The Act originally provided that utilities may apply to the Public Utilities Commission for reduced goals, but that they may not be reduced below 1%. In 2009, the state legislature amended the Act to reduce the level of savings during the first three years for natural gas utilities, establishing an in interim average annual savings goal of 0.75 percent over 2010-2012 (Minnesota Session Laws 2009, Ch. 110, Sec. 32).

The statute does not mandate that all the savings come from conservation improvement plans and traditional rebate-based programs. Statute 216B.2401 states:

> *It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.*

It is the responsibility of the utilities and retail suppliers to meet their own goals, which are currently the only means of meeting the statewide goals. There are no savings from government agencies, codes or standards in addition that contribute to meeting the statewide goal at this time.

For the largest investor-owned utilities during the first triennial period, CenterPoint Energy's natural gas energy efficiency plan is to increase savings from 0.73 to 0.78%, averaging the minimum 0.75%. Xcel Energy electric savings goals included in their approved triennial plan are 1.15% in 2010, 1.2% in 2011, and 1.3% in 2012.

The Societal Cost Test is the measure of cost-effectiveness that is predominantly used, although results from four types of cost effectiveness tests are included in proposed program plans. The assessment of cost effectiveness is very important to the entire EERS and CIP system.

Funding and Policy Approaches to Achieve Increased Savings

All experts interviewed agreed that it will be a serious challenge for Minnesota overall to achieve the energy savings required after 2010.

Electric
The NGEA policy allows for utilities to count supply-side savings above the first 1.0% in order to reach the 1.5% target. Some supply-side efforts utilities are undertaking include enhancements to the efficiency of distribution lines, feeders, transformers, and transmission lines.

To sustain and increase energy savings necessitated increased funding levels. The $111.2 million statewide budget for electric efficiency programs in 2009 eclipsed 2008 levels by $51.2 million. Spending levels will continue to rise as goals ramp-up and programs attempt to reach new sectors and achieve deeper levels of savings. Overall CIP spending by investor-owned utilities was projected to increase from $77 million in 2008 to $127 million in 2010, an increase of 65 percent. Xcel Energy's Minnesota subsidiary Northern States Power proposed 2010-12 combined gas and electric plan includes a budget of over $281 million and electric energy savings of 1,121 GWh. The proposed electric efficiency and demand annual budgets increase from $75 million in 2010 to 84 million in 2012.

Natural Gas
CenterPoint Energy spent approximately $16 million on efficiency programs in 2010, more than double the pre-EERS 2009 expenditures. Their initial 2010-2012 Triennial Conservation Improvement Program Filing from June 2009 budgeted for increases for both in 2011 and 2012, with only slight decreases in energy saved per dollar budgeted in spite of a 30% decline in savings per participant. The gap is made up by sharp year-over-year increases in program participants, from 104,000 planned in 2010, up by approximately 80% to 187,000 in 2012. Xcel's approved budget for natural gas efficiency programs was $13.9 million.

Significant barriers to extend and maintain natural gas savings into the future include the limited number of technologies in the residential sector, the fact that homes are already very efficient due to a cold climate that makes insulation the norm, and limited efficiency potential in many industries due to past program successes. For example, for turkey processors, there is one measure to install and the businesses have installed it already. Not all of the savings achieved are credited to utility programs to count toward savings goals. While CenterPoint Energy has increased the number of furnace rebates from 10,000 to 18,000 in one year, and many of the furnaces replaced were older, less efficient models, only the savings above code are attributed to the program. The furnace might have gone from 80 to 94 percent efficiency, but if code is 90%, most of the savings are not being counted toward the savings goal.

The three largest natural gas utilities hired Navigant Consulting to conduct a market potential study to assess these challenges to meet the energy savings goals of the NGEA. Results indicated that while there were energy efficiency opportunities to be had, at higher levels of savings the incremental costs climb. Based on the potential study findings, in 2009 the state legislature changed the law to reduce the savings goals for the 2010-2012 CIP triennial planning period. For CenterPoint Energy, the savings goals was reduced from 1.0% to .75%.

Administrative and Program Strategies to Achieve Increased Energy Savings

Electric
Examples of efforts underway to maintain and increase demand-side energy savings beginning in the current triennium include:

1. Increased rebates across all sectors and enhanced financial incentives to increase program participation.

2. One-stop services for residential customers to make participation easier and more accessible and therefore to increase participation. These initiatives to achieve savings in the residential sector, where the transaction cost per house is high, aim to get high-volume participation and savings for electric and natural gas through the "Home Energy Squad" brand. The largest investor-owned utilities are working with the Minnesota Center for Energy and Environment (MNCEE) Community Energy Services to use social marketing and direct installation of low-cost measures toward this end. The goal is to reach 50,000 households per year; in 2010, 6,000 households have participated.

3. The Trillion BTU program, run by the St. Paul Port Authority, brings funding from the Federal economic stimulus, the Minnesota Department of Commerce OES, and Xcel Energy in to improve overall efficiency, including energy efficiency. One trillion BTU's is just under 300,000 MWh. An explicit goal of the program is to help utilities achieve some of their savings goals under the NGEA of 2007. The funding sources are leveraged through a business loan program. The businesses agree to energy audits paid for by Xcel Energy Co.; engineering studies are performed on at the firms' facilities; 25% of the cost is paid by the business and 75% paid by Xcel. Installation of necessary physical improvements will be covered by a Port Authority Loan and an Xcel Energy Rebate.

4. Early pilot programs such as billing comparisons and expanding emphasis on behavioral program approaches. The contractor implementing the pilots is OPower. OPower sends energy use reports by mail and email to homeowners, comparing the homeowners' energy use with their neighbors and suggests energy savings ideas. This use of "normative messaging" has the benefit of engaging large numbers of people and motivating them to take action, boasting higher participation rates

Xcel Energy is going after increased savings in the industrial sector and working with top management on long-term energy saving investments. Historically, Xcel has emphasized business efficiency far more than residential. They see the biggest opportunities with large industrial customers over the long run. 70% of Xcel's retail electric sales are to commercial and industrial customers. New business sector programs added in Xcel's 2010-12 plan filing include: Turn-Key Services, Data Center Efficiency and Energy Advisory Service.

Xcel's short term plans start with increasing rebates. Most of their energy efficiency programs in Minnesota will offer a higher contribution to the customer's incremental cost of each efficiency measure, although they do not foresee this being a sustainable long term strategy by itself. They will put development effort into improving existing programs, leveraging holistic program success, and strengthening mid-market sales channels. Additional residential programs proposed in Xcel's plan filing include: Conservation Kits for Low Income customers, Energy Efficiency Support Services, Home Insulation Rebates, Refrigerator Recycling, Residential Quick Fix Service and School Education Kits.

<u>Natural Gas</u>

CenterPoint Energy, Xcel Energy, and Alliant each filed petitions to modify their previously-approved Natural Gas Conservation Improvement Programs in 2010. Alliant was granted approval to offer a rebate option for its Shared Savings program for the purpose of increasing participation; Xcel got permission to reduce the minimum qualifying efficiency of gas water heaters due to the lack of market availability.

Growth in savings in the near term at CenterPoint Energy—who serves two-thirds of the natural gas customers in the state—will come from the residential programs, with rebate programs for faucet aerators, low flow showerheads, furnaces, and water heaters. A CenterPoint Energy representative stated that all of the growth in next 3 to 4 years is expected to come from the residential sector, and this growth will cost more per therm of saved energy. Four new programs were added in 2010: insulation, air sealing, pilotless hearth rebates, and three tiers of furnaces (Kline).

The business side faces limitations. The industrial natural gas efficiency sector in CenterPoint's service territory is increasingly saturated and the number of marginally cost-effective efficiency opportunities is declining. One approach to increasing participation has been to increase commercial market segmentation, focusing on K through 12 education, health care, multi-family housing, higher education, and restaurants. While food service was an important part of the portfolio, it is a diffuse area, similar to single family residential in that the total savings per project are relatively low and administrative costs relatively high.

Previously, the 2007-9 plan that was approved included no new incremental technologies, only increases in participation.

Early Results, Responses, and Outlook

Minnesota electric utilities have been increasing their savings each year, as show below in Table 22

Table 22: Minnesota Statewide Electric Savings Achieved 2007-2009

Year	Statewide Electric Savings Achieved (MWh)	Savings as % of 2007 sales
2007	463,999	0.68%
2008	600,179	0.88%
2009	649,379	0.95%

Source: Annual Legislative Report on GHG Reductions, January 2011

Several hurdles remain for utility energy efficiency programs to meet their savings goals into the future, most of which are policy-driven, although they all have implications for program administration, design, and implementation.

The Minnesota Division of Energy Resources has contracted with the Minnesota Environmental Initiative (MEI) to lead a multi-stakeholder process to find ways to achieve the 1.5% goal. They are focusing specifically on four "policy barrier issue areas": behavioral programs, low income, codes and standards, and utility infrastructure improvements noted above in this report. The "1.5% Energy Efficiency Solutions Project" has convened technical working groups on each of the four main issues to develop proposed solutions. The Project concluded on schedule in February 2011, issuing a self-titled final report with their findings.[44]

On the demand side, the impact of higher appliance standards and building codes on utility savings and how this will be addressed will be important considerations. MEI described the problem like this:

> ... passage of more stringent codes and standards can have a negative impact on utility programs. As codes change the baseline conditions for energy efficient equipment that exceeds the code minimum is adjusted, which can reduce a utility's ability to claim savings and reduce the cost effectiveness of program portfolios.

In short, higher baselines mean lower savings attributable to utility efficiency programs. The technical working group on codes and standards has been looking at that this from multiple perspectives. They are investigating how quickly new baselines would be applied, methodologies (for the state as well as utilities) to track savings resulting from implementation of new codes and standards, and developing the business-as-usual scenario for code implementation. The recommendation is that the baseline be the codes that were in effect in 2007 at the time of NGEA enactment. Utilities may have a role to play in the implementation of codes and standards, possibly operating a code-compliance program within its service territory, and getting credit for some of the resulting energy savings.

The NGEA policy requirement measures annual "first year" savings, not cumulative energy savings, which constrains which efficiency opportunities utilities may use. Measures with lives of 12 to 15 years result in greater energy savings than, for example, behavioral programs with a one year measure life. So, while

[44] 1.5 Percent Energy Efficiency Solutions Project: Final Report. Minnesota Environmental Initiative. March 2011.

the incentive structure encourages utilities to pursue expanded and additional behavioral programs, the actual cumulative energy resource savings in future years will be less than if measures with more-persistent savings had been adopted.

Xcel Energy describes their future efficiency program success as dependent on many factors, including the growth of their existing program portfolio, emerging energy efficient equipment technologies, the development of methodologies to quantify savings from nontraditional programs and market transformation. Two key energy savings areas Xcel is looking at that fit squarely with the 1.5% Energy Efficiency Solutions Project are behavioral programs and codes and standards.

Prognosis

Xcel Energy will strive to meet the electric 1.5% goal over the long term, possibly during the next triennial planning period from 2013 to 2015. Current findings of achievable potential do not support saving 1.5% per year beyond 2015 using traditional programs and current technologies, even with up to 75% rebate levels. Long-standing, leading energy efficiency programs have captured much of the most cost-effective energy savings. Xcel will be looking to a new electric efficiency potential study in 2011 to identify additional efficiency opportunities. Over the long run, their strategic planning and modeling will consider current trends in existing programs as well as expected changes in lighting standards, motor standards, and possible changes to cooling and new construction codes.

For CenterPoint Energy's Minnesota natural gas operations, one representative conceded that the goal of 1% annual savings might not be reached until 2015.

References

CenterPoint Energy. 2009. *CenterPoint Energy's 2010 - 2012 Triennial Conservation Improvement Program Filing.* Docket No. G008/CIP - 09 - xxx.

Haase, J. 2011. Presentation at Midwest Energy Efficiency Alliance 2011 Midwest Energy Solutions Conference, Chicago, Ill. January 13.

Kline, A. .2009. "Where Next? Meeting New Aggressive Energy Savings Targets for Natural Gas Utilities in Minnesota". Presentation at ACEEE Energy Efficiency as a Resource Conference, Chicago, Ill. September 28.

[MOES] Minnesota Office of Energy Security. 2010. *2007–2008 Minnesota Conservation Improvement Program Energy And Carbon Dioxide Savings Report* Minnesota Office of Energy Security Pursuant to Minnesota Statutes §216B.241, subd. 1c(g) January 15, 2010

Rhodes, K. 2011. Presentation at Midwest Energy Efficiency Alliance 2011 Midwest Energy Solutions Conference, Chicago, Ill. January 13.

Xcel Energy. 2009. *Xcel Energy 2010/2011/2012 Triennial Plan Minnesota Electric and Natural Gas Conservation Improvement Program* E,G002/CIP-09-198

New York

Background

Second only to California in total spending on utility energy efficiency programs, New York has arguably one of the most extensive and complex utility energy-efficiency infrastructures of any state. The overall effort is designed to support a broad spectrum of activities including technology research and development, business and market support, and expansion of market opportunities for energy efficiency products and services. New York's energy efficiency program spending was almost double the "third place" state every year from 2006 to 2009. New York was one of the first states to establish a system benefits charge (SBC) to support energy efficiency and other public benefits energy programs. The current and more recent generations of programs are required by regulatory orders issued by the New York Public Service Commission (NYPSC) and are the result of NYPSC cases dating back to 1996. The state, and the New York Power Authority (NYPA) in particular, have played pioneering roles in energy efficiency since the 1970's, including staples such as on-bill financing, whole building systems, and energy management systems. In the 1980's, NYPA ceased providing rebates and direct financial incentives for energy efficiency projects entirely and since then has lent investment capital, partnering with utilities' programs.

One of New York's longest running energy efficiency programs is New York Energy $mart^{sm}, initiated by the NYPSC for the 13-year period from 1998 to 2011. The program is administered by the New York State Energy Research and Development Authority (NYSERDA) and was designed as a market transformation effort, while simultaneously supporting resource acquisition. The current NYSERDA five-year funding cycle of SBC programs, known as "SBC III," ends in June 2011.

While NYSERDA has been the largest energy efficiency program administrator since the 1990's, there are three additional major energy efficiency institutions in New York State, each with their own functions and roles. NYPA, the largest state public power organization in the U.S., operates more than a dozen generation facilities, primarily hydroelectric plants, as well as over 1,400 miles of transmission lines. NYPA provides financing for energy efficiency investments and low-cost power for economic development, as well as supplying electricity to distribution utilities and cooperatives. Long Island Power Authority (LIPA), while also a state agency with substantial transmission and distribution assets, is structured as a non-profit municipal electricity provider. LIPA does not own any generation plants on Long Island.

In the fourth category are the investor-owned utilities. The largest of these are Consolidated Edison in New York City and National Grid upstate, through its operating company, the Niagara Mohawk Power Corporation. Historically, since the initiation of large-scale energy efficiency program efforts at NYSERDA, the utilities had not had major energy efficiency programs of their own. That changed recently when. the PSC issued an order to create the state energy efficiency portfolio standard (EEPS) in 2008.

From 2006 to 2008, ratepayer funding through the SBC for electric energy efficiency programs was relatively steady in the range of $220 to $240 million per year. Natural gas funding was $50 million in 2008.

Decoupling

Following an April 2007 order (Cases 03-E-0640 and 06-G-0746), electric and gas utilities must file proposals for true-up based decoupling mechanisms in ongoing and new rate cases. A revenue-per-class decoupling mechanism has been approved for both Consolidated Edison and Orange & Rockland electric utilities. True-ups occur annually under these mechanisms. Con Ed's revenue-per-customer gas decoupling program received approval to continue from the Department of Public Service (Case 06-G-1332, May 19, 2009). National Fuel Distribution also implements revenue-per-customer decoupling.

Shareholder Incentives

On August 22, 2008, the PSC established incentives for utility energy efficiency programs (Case 07-M-0548). The maximum potential incentives will be determined by the percentage of estimated overall program costs. The metric for utility performance is achieved megawatt-hour reductions. A unique trait of this incentive mechanism is the infusion of the risks of negative adjustments for utilities that achieve less than 70% of its efficiency target. Utilities achieving more than 80% of their targets receive incentives. On achieving 100% of its target, a utility is rewarded the maximum incentive.

New York's Energy Efficiency Portfolio Standard Policy

On June 23, 2008, the NYPSC issued a decision creating the New York Energy Efficiency Portfolio Standard (EEPS), part of a statewide program to reduce electricity usage by 15% of forecast levels by 2015, with slightly lower goals for natural gas savings. The Commission set interim energy savings goals and approved funding through the year 2011. The State's utilities were mandated to file proposed energy efficiency programs, and NYSERDA was invited to submit energy efficiency program proposals for approval. The savings targets began in 2008 at 0.5% savings relative to 2007 forecast sales and ramp up for several years, achieving an annual average of over 2% each year through 2015. From the initial order, the annual electric savings targets were set as shown in Table 23.[45]

Table 23: New York Annual Electric Savings Targets, 2009-2015

2009	2010	2011	2012	2013	2014	2015
2.10%	2.12%	2.16%	2.18%	2.20%	2.23%	2.26%

State agency and utility program administrators all contribute to New York's '15 by 15' goal, as well as savings derived from other state agencies, codes and standards, and improvements to transmission and distribution. LIPA and NYPA, however, are not bound to the EEPS targets by regulation since they are not under the jurisdiction of the NYPSC. Thus while total electricity sales under the 15% by 2015 standard would require savings of roughly 29.4 million MWh annually in 2015, the NYPSC has approved program targets that leave roughly 7.7 million MWh to be achieved by programs outside its jurisdiction.

NYPSC also approved natural gas efficiency targets in May 2009. The targets aim to save 4.34 Bcf annually through the end of 2011 and 3.45 Bcf annually beyond 2011. The downward revision of the target reflects a likely change in program balance following the exhaustion of federal stimulus funding. The natural gas targets are estimated savings goals and do not represent binding commitments, but rather will be used for planning purposes. Combined with reductions from other sources, this target will result in a 14.7% reduction in estimated gas usage by 2020.

Funding and Policy Approaches to Achieve Increased Savings

Funding Increases

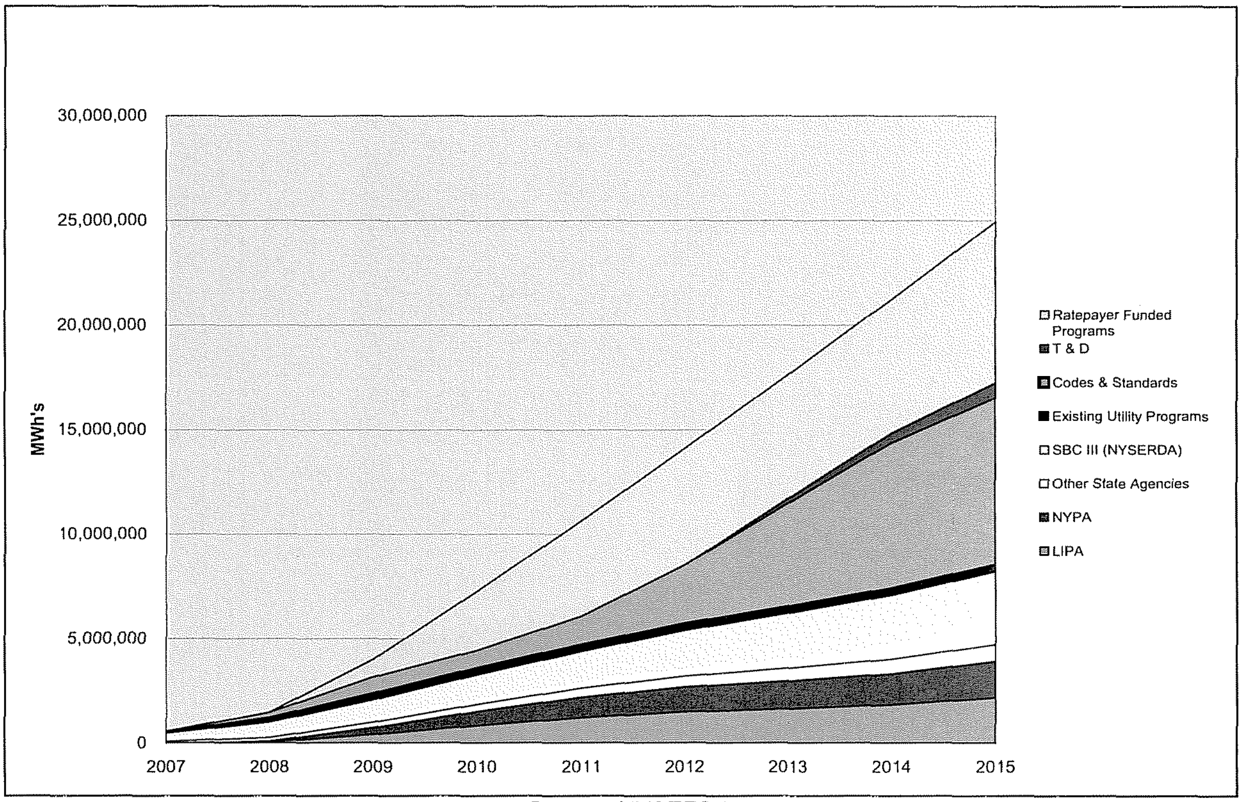
One of the primary changes made in order to facilitate achievement of New York's EEPS energy savings goals has been a major increase in funding for energy efficiency resource acquisition programs, from the SBC (going into NYSERDA and utility EEPS programs) and other sources. The 2008 PSC order directed New York's investor-owned utilities to commence collection, through the System Benefits Charge (SBC), of additional funds to support the EEPS through 2011. For electric energy efficiency programs, the total budget for 2009 increased to $378 million. LIPA's new ten-year, expanded energy efficiency plan will be funded by an efficiency fee on customer bills that the ELI Web site compares to the SBC. NYPA continues to expand their volume of lending.

Savings from Other State Policies

EEPS funding increases will not need to pay for the acquisition of all MWh energy savings needed to reach the statewide "15 by 15" goal. Electricity savings will come from a variety of sources in addition to the expansion or modification of traditional energy efficiency programs at utilities and state agencies, including efficiency gains through transmission and distribution systems, and, most significantly, building codes and appliance standards. This is illustrated in Figure 4 below, from the State Energy Plan.

[45] CASE 07-M-0548, June 23, 2008

Figure 4. Achieving New York State's '15 by 15' Goal



Source: NYSERDA

Source: New York State Energy Plan, Volume I. December 2009.
http://www.nysenergyplan.com/final/New_York_State_Energy_Plan_VolumeI.pdf

In the chart above, four of the larger savings "wedges" correspond to portfolios of relatively traditional electric efficiency programs: New Ratepayer Funded (Utility Administered) Programs, Existing Utility Programs, the resource acquisition components of SBC III (NYSERDA), and some of the LIPA programs. The above graph was made prior to the currently-pending re-alignment of "resource acquisition" programs and Technology and Market Development programs.

Additional Utility Programs

Regarding Ratepayer Funded Programs, program administrators submitted plans in 2009 to the PSC for "Fast Track" programs under the EEPS, for both natural gas and electric programs. During the next year and a half following the EEPS Order, the PSC approved 85 electric and natural gas programs. For example, Consolidated Edison and Orange & Rockland Utilities jointly filed for residential electric HVAC, residential gas HVAC, and Small Business Direct Install program plans. These EEPS plans were for the 2009-2011 three year period. Con Edison's Small Business Direct Install Program plan as proposed was to save 289,909 MWh, the sum of the first-year savings in each of the three years. Their residential gas HVAC was slated to save 188,632 dekatherms over the same period.

LIPA

LIPA is functioning under an overall ten-year Electric Resource Plan that runs from 2010 to 2020; their energy efficiency organization, Efficiency Long Island (ELI), has a 10 year, $924 million energy efficiency plan that began at the start of 2009 and will continue through the end of 2018. ELI substantially expands the portfolio of energy-efficiency programs and funding beyond those that were in place through its predecessor, the Clean Energy Initiative (CEI). CEI ran from 1999 to 2008, with a total budget of $355 million, which included renewables, research and development, and conservation in addition to efficiency spending.

NYPA Efficiency Investment Financing
NYPA does not provide traditional incentive-based efficiency programs, but instead makes energy savings possible via their lending efforts. Their plans to achieve greater energy savings are based on increased investment. They currently have $300 million in loans outstanding. Over the course of the EEPS period from 2008 to 2015, NYPA will have provided $1.5 billion in financing for energy efficiency projects, almost as much as their total since inception. NYPA borrows short-term commercial paper notes and does not receive funds from the SBC. Customers are large, stable institutions such as the City of New York and the state university campuses, and therefore represent extremely low default risk. This enables NYPA to lend at rates as low as 0.7%.

Administrative and Program Strategies to Achieve Increased Energy Savings

Institutional-Level
On September 20, 2010, NYSERDA petitioned the NYPSC to accept its *Vision for the Future*, a four point plan covering the next five years of the SBC funded energy efficiency programs. In spite of the diversity of organizations that contribute to the statewide EEPS goals, NYSERDA efforts overall still account for approximately two-thirds of the electric savings and about sixty percent of the natural gas energy savings. NYSERDA's proposal would continue SBC funding at the increased levels that have been in place since the 2008 Order establishing the EEPS.

As the largest program administrator, NYSERDA is re-aligning the administrative structure that houses energy efficiency programs and portfolios. NYSERDA has received approval from NYPSC to reorganize EEPS and SBC III funding and portfolio composition. Effective July 1, 2011, Resource Acquisition programs in the SBC portfolio, and their budgeted funds, will be extended for six months and moved over to merge into their EEPS counterparts. A second portfolio, Technology and Market Development, will continue to stay within SBC and continue to be funded with SBC funds.

These re-aligned programs are both gas and electric and include Residential Multi-Family Building Performance, Low Income Multi-Family Building Performance, EmPower NY, Existing Facilities, High Performance New Buildings, and Technical Assistance.

Two other SBC III resource acquisition programs that have not had parallel EEPS programs running concurrently are the Single Family Home Performance program and the Low Income Single Family Home Performance program. These make up $17 million ($11 million electric, $6 million gas) of NYSERDA's $98 million annual resource acquisition budget. The NYPSC ordered EEPS staff to decide whether the programs will continue and if so, to propose new operating plans.

The natural gas measures that have been funded by electric ratepayers in the past under the System Benefits Charge will be funded by gas ratepayers when the extension period begins in July 2011.

Sector-Level
Among the major program administrators contacted for this report, LIPA volunteered its expectation that most of the growth in savings in the coming years at Efficiency Long Island will come on the commercial side, from prescriptive lighting, custom, and whole-building comprehensive programs.

Program-Level
Program offerings at LIPA which they are confident will achieve their planned energy savings levels in the near term include Home Performance with ENERGY STAR, direct install (HP Direct), central air conditioning, low income REAP, and a wide array of product and appliance incentive programs such as air conditioners, pool pumps, and a refrigerator bounty program.

LIPA has shifted its marketing and communications approaches to include video testimonials, more visuals, and YouTube. In the past, customers were notified of available rebates via mailings, tradeshows, bill stuffers, local papers. Now advertising and marketing are focused on the decision makers—if the customer is a school, for example, the buildings and grounds manager would be targeted. Efforts are underway to improve marketing coordination with the trades, because the tradesmen need to both know the efficiency programs and be able to sell it. For example, a local electrician needs to be aware of which rebates are available and how much.

NYPA also reports marketing more aggressively. For its large downstate electric customers, including the City of New York, NYPA is developing sophisticated tools such as internet-based energy management systems.

Consolidated Edison, after having some programs implemented for over one year, does not anticipate any major changes during this program cycle to the mix of measures that are included in programs because of the time it takes to petition the PSC for modifications. As of late 2010, it was considering increasing rebates for residential sector programs.

Early Results, Responses, and Outlook

Although some results have been inconsistent and there have been challenges to overcome during the first two years since the EEPS Order in 2008, there have been many initial successes.

Due to the scale and complexity of utility energy efficiency institutions and programs, one common element linking successful efforts to ramp-up savings is collaboration—especially collaboration across institutions that enables integration, coordination, and standardization. Everyone interviewed for this report mentioned how important collaboration is to the structure and effective functioning of the state system as a whole.

Several challenges arose which influenced the effectiveness of the initial EEPS program ramp-up, many of which are being addressed through collaborative approaches.

Challenges

In the first years of the EEPS, the investor-owned utilities as a group were not on target to meet their goals. Con Edison reported falling short of their goals for 2010, in spite of having built the infrastructure to achieve required savings going forward, and they attribute this to effects of the economic recession. The investor-owned utilities have petitioned the PSC to change the incentive structure, which currently penalizes them if they acquire less than 70% of the target savings level. New York's largest utilities—including Con Edison, National Grid, and LIPA—are in a "rapid start" situation, as they are new administrators of some of the largest efficiency portfolios in the nation on a steep growth curve. They are working alongside NYSERDA and NYPA, two of the most well-established and sophisticated administrators and implementers.

Table 24:Statewide Portfolio through December 31, 2010[46]

	All Utilities	NYSERDA	New York State
Percent of 2009-11 Net MWh Target Acquired	35%	54%	**47%**
Percent of 2009-11 Net Dekatherm Target Acquired	80%	28%	**51%**
Percent of 2009-11 Budget Spent	44%	29%	**37%**

Several people interviewed for this report identified market confusion as a concern. Since NYSERDA had been the sole supplier of energy efficiency for so long, customer awareness of the IOU programs is and has been low. When consumers are aware, having two options makes their decisions more complicated. However, customers in general are not complaining because it provides them with multiple financial incentive options from which to choose, allowing them to choose those that best meet their needs. A NYPA representative described their overall model toward financing efficiency as a partnership with a very collaborative style in which they meet frequently with NYSERDA and the utilities, in a "constant effort to reduce market confusion and coordinate [funding sources] EEPS, RGGI, and ARRA" [New York energy

[46] Energy Efficiency Portfolio Standard Program Implementation Status Through the 4th Quarter of 2010. Prepared by: Office of Energy Efficiency and Environment. March, 2011

efficiency portfolio standard, Regional Greenhouse Gas Initiative, and American Recovery and Reinvestment Act].

A third challenge has been that program plans had initially been designed to meet cost-effectiveness standards at the program level. The PSC interpretation shifted toward measure-level tests after many initial program plans had already been approved. This may have the general effect of improving savings-per-dollar in the short run, but disallowing some of the less cost-effective energy-saving measures that would otherwise be implemented by being bundled in with highly cost-effective measures.

Positive Developments

One approach to coordination has been the alignment of programs by industry. For example, National Grid and NYSERDA have a collaborative effort in the health care sector effort centered on hospitals. NYSERDA has a new, fast-growing program focusing on data center efficiency with Consolidated Edison, which has the service territory with the highest concentration of data centers in the state. NYPA and the Electric Power Research Institute are also involved in the data center partnership.

Con Edison has also collaborated at the program level, working with NYPA, New York State Electric and Gas Company (NYSEG), National Grid and others to develop a common delivery platform for their Small Business Direct Install Program.[47]

In a major move toward standardization, on October 18, 2010, the NYPSC issued an Order Approving *Consolidation and Revision of Technical Manuals*, in which they approved the "New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs—Residential, Multi-Family and Commercial/Industrial Measures." The order updated and consolidated five separate technical manuals that had been approved since the issuance of the EEPS order, covering all major energy efficiency sectors.

NYSERDA's New York Energy $mart[sm] Commercial Lighting Program, recently recognized by ACEEE in *States Stepping Forward: Best Practices For State-Led Energy Efficiency Programs*, exemplifies the benefits available when programs are integrated and aligned. The program saves 78.6 GWh annually. In our report, we write:

> For market transformation programs to remain viable and effective, they must evolve and address the changing needs of participants and end-users. . . . Integration and conformity with other related programs, emerging technologies, and ever-changing best practices are also critical.(Sciortino 2010)

Prognosis

Program administrators state that the outlook is good for New York to achieve '15 by 15' EEPS energy savings goals. A NYSERDA representative said that there is pent-up demand for energy efficiency projects, and that NYSERDA can meet savings goals for commercial and industrial sectors. This is significant because business sector savings historically make up between two-thirds and three-quarters of the total cumulative savings. Consolidated Edison claims they will meet their full goals by 2015. NYPA, while not mandated to do their proportional share of the '15 by 15' EEPS as utilities are, predicts they will continue to meet or exceed their lending goals for energy efficiency investments.

Reference

Sciortino, M. 2010. *States Stepping Forward: Best Practices For State-Led Energy Efficiency Programs*. Washington, D.C.: American Council for an Energy-Efficient Economy.

[47] Expedited Fast Track Electric and Gas Energy Efficiency Programs Implementation Plans, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Case 08-E-1007, 08-G-1008, 08-E-1003, 08-G-1004

Vermont

Background

Vermont has had extensive energy efficiency programs since 1990. Originally, programs were run by the state's utilities under jurisdiction of the Vermont Public Service Board (PSB), but in 1999 the PSB transferred operations to Efficiency Vermont, a statewide[48] "energy efficiency utility" supported by public benefits funding. Efficiency Vermont offers energy efficiency programs and services in the electricity sector as well as in the unregulated fuels sector including wood, propane, and heating oil. There are also natural gas efficiency programs administered and implemented by one utility, Vermont Gas Systems, Inc. Natural gas efficiency programs are supported by legislation and regulation of heating and process fuels (30 V.S.A. section 235(d); Docket No. 5270 VGS-1, 2) and began in 1993.The natural gas programs saved 97,924 MCF in 2008 and have saved over 800,000 MCF since their beginning in 1993.

Prior to the ramp-ups in funding and savings levels over the last few years that are discussed below, Vermont's energy efficiency programs through Efficiency Vermont had already been yielding significant results. By 2005, savings had cumulatively met over 5% of Vermont's electricity requirements already. In 2006, efficiency savings were about 1% of sales.

Vermont pioneered the model of a statewide "energy efficiency utility" (EEU) after Vermont enacted legislation in 1999 authorizing Vermont Public Service Board (PSB) to collect a volumetric charge on all electric utility customers' bills to support energy efficiency programs. Volumetric charges are assessed on a per kWh or per therm basis. Vermont PSB created the EEU, Efficiency Vermont, to use these public benefits funds to provide programs and services that save money and conserve energy.

The PSB role is similar to that of a Commission in other states; the Department of Public Service is separate and is part of the executive branch. Vermont is one of two states that established statewide public benefits funding without electric utility restructuring. The program administration model has the PSB at the top. Until recently, Efficiency Vermont was run by a competitively-selected contractor, the nonprofit Vermont Energy Investment Corporation (VEIC), but now VEIC has a long-term appointment. The previous structure was that the PSB also employed a contract administrator and a fiscal agent, with an advisory board to provide oversight. The fiscal agent received monies collected by the electric distribution companies and disbursed funds to Efficiency Vermont. Now, VEIC is much more similar to a distribution utility, and the contract administrator and advisor board have been eliminated.

Decoupling

Green Mountain Power (GMP) has an Alternative Regulation Plan, implementing partial revenue-per-customer decoupling, which was approved for a three year period by the PSB on December 22, 2006, and extended three times since then, most recently for the three years beginning October 1, 2010 (Order 7585). The plan includes two annual adjustments to rates, the Earnings Sharing Adjustor and the base rate adjustment, both calculated on a yearly basis (Docket Nos. 7175, 7176. Order 7438). Central Vermont Public Service (CVPS) received approval for an alternative regulatory plan in September 2008, under which it may adjust rates every year based on forecast costs and sales. The plan period ends December 31, 2011 (Docket No. 7336).

Performance Incentives

Shareholders of investor-owned utilities such as GMP and CVPS are not eligible for shareholder incentives because those utilities do not implement the energy-efficiency programs. VEIC, a nonprofit organization, is eligible to receive a performance incentive for meeting or exceeding performance goals established in its Order of Appointment. They do not receive compensation until the achievement has been confirmed by the DPS and the PSB has made a final ruling.

[48] Burlington Electric Department runs its own efficiency programs within its jurisdiction.

Energy Efficiency Portfolio Standard Policy

Vermont does not have energy efficiency portfolio standard legislation with a set schedule of energy-savings percentages for each year as most states with portfolio or resource standards do. Instead, Vermont law requires EEU budgets to be set at a level that would realize "all reasonably available, cost-effective energy efficiency." Until recently, specific energy-savings levels—not "soft" goals or targets—were then fixed contractually as part of the negotiation process with EEU contractor VEIC. Under the new structure, there is a "demand resources plan" to set goals and budgets for the next 20 years, corresponding with the long-range transmission plan. These goals and budgets are revised every 3 years.

Much of the legislative and regulatory framework that provides the foundation for demand-side resources to play the major role that they do in meeting the state's energy needs has been in place since the 1990's. State statute (30 VSA Sec. 218c) mandates all electric and natural gas utilities to prepare and implement least-cost integrated resource plans:

> . . . at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

Vermont has a well-established regulatory process to factor the Energy Efficiency Utility's energy savings into utility companies' load forecasts.

Funding and Policy Approaches to Achieve Increased Savings

Substantial funding increases through the Energy Efficiency Charge (EEC) included within customer rates have built on this foundation to enable the unprecedented energy savings achieved over the last five years.

One turning point came from the state legislature in the form of Act 61 of 2005, which removed the spending cap on the EEU annual budget. This gave the PSB the flexibility to determine appropriate funding levels in the context of the integrated resource planning process. Vermont already had the highest per-capita investment in electric efficiency of any state at $22.54 per person in 2004, prior to the two most recent performance cycles, despite having reached their spending cap. A 2006 PSB Order increased funding from the previous maximum of $17.5 million up to $30 million per year for the next three years. The current plan for 2009-11 increases that to approximately $33 million per year from ratepayers. Including Regional Greenhouse Gas Initiative (RGGI) and Forward-Capacity Market (FCM) funds used for nonregulated fuels efficiency programs pushes the annual total into the $40 million range. In late 2006, Efficiency Vermont began to expand its programs again and targeted four areas of the state with significant transmission and distribution constraints, called geo-targets, for concentrated efforts to reduce peak demand. These areas have also achieved incremental energy savings because of the concentrated efforts on the community level.

The EEU structure ensures that as an efficiency program implementer, VEIC does not have conflicting incentives. They are not an investor-owned for-profit utility, have no rate base, and thus, no throughput incentive. The positive incentive is very strong: for the period from January 1, 2009 to December 31, 2011, VEIC can earn up to $2,180,000 in awards for meeting electric energy saving goals, calculated by a weighted formula.

Another important feature of the policy environment for efficiency in Vermont is that long-term planning and long-term perspective for are accorded great importance. This is being demonstrated by the Investigation into Energy Efficiency Utility Structure (Docket 7466) at the PSB. The investigation considered switching from a 3-year energy efficiency utility performance contract to a 12-year Order of Appointment. The new structure has 20-year electric energy efficiency budgets and 10-year goals.

Natural gas comprises a comparatively small fraction of the energy used in Vermont relative to other states. Still, the scope, funding, and impacts of the energy efficiency programs administered and implemented by Vermont Gas Systems have grown over the last ten years. Annual program spending on all natural gas DSM has increased from $800,000 in 2000 to $1.98 million in 2009. Annualized energy savings have increased from 42,000 MCF in 2000 to over 60,000 each year since 2006.

Administrative and Program Strategies to Achieve Increased Energy Savings

Within each three-year performance contract period, Efficiency Vermont has program plans that are updated annually. The 2011 plan builds on 2010's established strategies in five markets: business new construction, business retrofit, residential new construction, residential retrofit, and efficient products.

Efficiency Vermont has as many if not more staff per dollar of budget than any comparable efficiency organization in the country, such as Energy Trust of Oregon or Wisconsin Focus on Energy. Consequently there is much less emphasis on rebates and financial incentives and more on people. EV gives this approach credit for a greater yield of energy savings.

EV has consolidated business Account Management, which now account for a quarter of total portfolio savings. They emphasize a long-term, relationship-based approach that addresses market opportunities, not urging retrofit. The 300 largest accounts will always be working with the same person at EV, so customers build relationships with individuals, not only with the organization. For example, if a plant or facility manager is planning investments, they will call their EV Account Manager first, early in the planning and budgeting process. They can access money and advice from EV, technical assistance with process improvements, and actively build-in more efficiency savings into their construction or retrofit projects. With this approach the customers know they have a trusted resource to bring in on major projects to increase energy efficiency. There is much less resistance in the interactions between business customers and Efficiency Vermont Account Managers. This is the counter to an approach that says, in effect, "I'm here to do an audit, in order to get your business, to make changes you did not expect."

The Efficient Products Program, with a large share from lighting, makes up another quarter of total portfolio savings. With high CFL saturation, they are moving toward dimmable, 3-way and specialty CFL's and LED's. From 2009 to 2010, resources were shifted to increase specialty bulbs up from 10 percent to 20 percent. Much of this has been done by going upstream, buying down the price of CFL's to 99 cents and making them more widely available at retail, even including convenience stores and gas stations.

Within lighting, an approach gaining substantial energy savings is upstream commercial efforts featuring the use of lighting designers to decrease lighting density. EV has built strong relationships with lighting designers, who can help customers save money that in turn helps to pay for their lighting design audits. Working under a performance-based appointment allows EV to allocate funds to where they can buy the most energy savings with each budget dollar. Relative to other program administrators, they do more custom projects, and are not constrained to work off of prescriptive measures and prescriptive projects. This allows for incentives to be entirely negotiated with the customer, with EV effectively buying down the cost of the project or measure until it becomes an attractive investment for them.

The evaluation, measurement, and verification environment they operate in may be a contributing factor toward their nation-leading levels of savings achieved: Efficiency Vermont gets credit for approximately 90 percent of the energy savings they report to the State. As the primary and clearly dominant efficiency entity in Vermont for more than a decade, there is little competition for energy savings attribution, and evaluated energy savings include spillover that compensates for free-ridership. A related issue is the use of the Societal Cost Test to measure cost-effectiveness, which allows some efficiency measures to be deemed as having a positive benefit-cost ratio, which may not be the case under other cost-effectiveness tests. The VEIC appointment does, however, require a 1.2:1 factor of gross electric benefits to spending, which they far exceed.

Results, Responses, and Outlook

Efficiency Vermont has saved 311 GWh between 2006 and 2008, exceeding its three-year savings goal of 261.7 GWh. In 2007 and 2008, savings from energy efficiency measures more than offset the average underlying rate of electricity load growth. The GWh savings goal for the current period established in the contract is 359,700, a thirty-seven percent increase over the prior goal. They surpassed 2009 savings of 85,000 MWhs in 2010 by 29,000 MWhs, savings 114,000 MWhs for a 34% increase.[49]

The aggressive electric energy efficiency measures have proven to be consistently cost-effective. In 2007, Efficiency Vermont saved 103 GWh at a cost of 2.7 cents per kilowatt-hour (over the life of the measures) according to its annual reports. In 2008, Efficiency Vermont saved 150 GWh at a cost of 2.9 cents per kilowatt-hour, spending $31 million on efficiency programs. Vermont plans to reduce its electricity consumption by 2% per year during the current three-year cycle, according to plans for 2009-2011. In 2009, the annualized natural gas savings attained by Vermont Gas Systems dropped from 97,924 mcf to

Efficiency Vermont essentially does not offer traditional energy efficiency programs at all. As they operate under a performance contract model, they have flexibility and wide latitude relative to program administrators in other states to change their approaches to achieve their savings targets. Barriers to achieving energy savings faced in other states are much smaller, have been addressed effectively, or are nonexistent in Vermont. According to one staff member at EV, "We don't have a set of twelve programs with clever names to give customers rebates. We get paid for results."

Staff attribute their success to the alignment between their non-profit structure and their mission: to reduce the environmental and economic costs of energy use. They contrast this with an investor-owned utility having the primary purpose of serving shareholders, and with for-profit program implementers that may have mixed motives and incentives. EV, on the other hand, has a deep culture of innovation and experimentation centered solely on saving energy.

Prognosis

Vermont has achieved highest percent energy savings in the electric sector of any state. In recent years the GWh savings noted above correspond to more than 2% of total sales. Efficiency Vermont is now aiming for 3%, staking out territory in a class by itself ahead of the next tier of states. This track record of energy savings is a result of the combined effect of the legislative and regulatory policies Vermont has in place and by the overall design, approach, and management innovation of Efficiency Vermont (EV).

[49] Efficiency Vermont 2010 Annual Savings Claim. April 1, 2011
http://www.efficiencyvermont.com/about_us/information_reports/annual_reports.aspx

APPENDIX C: RAPID STARTS STATES CASE STUDIES

Arizona

Background

Under the Arizona Administrative Code, electric and gas utilities must file energy conservation plans that must, at a minimum, include customer education and assistance programs to help the public reduce energy consumption and bolster participation in energy conservation programs sponsored by governmental agencies.

Two of the major investor-owned electric utilities in Arizona, Arizona Public Service Company and Tuscon Electric Power Company, operate a variety of demand-side management and energy efficiency programs, applicable to a range of customers. Programs are administered by individual utilities and funding varies by utility. Programs are submitted to and approval is required from the Arizona Corporation Commission (ACC).

Arizona Public Service (APS) operates a number of successful DSM programs for residential and non-residential customers. APS Request for Rate Increase, Docket No. E-01345A-08-0172S, was approved in January, 2010, as Decision Number 71460, which included its energy efficiency implementation plan. According to its 2009 resource plan that maps a strategy for the years 2009-2025, energy efficiency programs will continue to grow. Tucson Electric Power Company (TEP) received approval for its 2011-2012 Energy Efficiency Implementation Plan in February 2011 (Docket No. E-01933A-11-0055).

Southwest Gas and UniSource Energy, the two natural gas utilities in Arizona, also operate energy efficiency programs—primarily rebates for installation of certain energy efficient equipment. Salt River Project (SRP), a public utility, recently released plans to ramp up its energy efficiency programs. Over the next five years, the company plans to invest more than $200 million in electric energy-efficiency and demand response programs.

Arizona's Energy Efficiency Resource Standard Policy

On December 18, 2009 the ACC ordered that all investor-owned utilities and rural electric cooperatives achieve 1.25% annual savings as a percent of the retail energy sales in the prior calendar year, ramping up to 2% beginning in 2014. By 2020, the state should reach 20% cumulative savings, plus up to a 2% credit for peak demand reductions from demand response programs, for a total standard of 22%. Electric distribution cooperatives are required to meet 75% of the standard in any year. Utilities can count energy supply from combined heat and power systems that do not qualify under the state's Renewable Energy Standards towards the standard, as well as 1/3 of the measured savings from new building codes. Utilities are allowed to credit energy savings achieved during 2005-2010 towards the requirements beginning in 2016. See Docket No. RE-00000C-09-0427, Decision No. 71436.

Utilities must submit an annual implementation plan to detail progress in meeting goals and estimate cost and energy savings for programs over the next two calendar years. Utilities may recover the prudent costs of energy efficiency programs through a DSM tariff and the decision also allows utilities to request the Commission to consider the use of performance incentives to assist in achieving the goals.

Arizona has natural gas efficiency standards aiming to achieve 6% cumulative savings by 2020 (Docket No. 000009B-09-0428 Dec. No. 71855). The companies are allowed to reach this goal through both demand side management (DSM) and renewable energy resource technology (RET) programs.

SRP's publicly elected Board sets the company's energy efficiency and renewable energy. Based on a Feb 2006 Resolution, the energy savings goal is currently 15% of retail requirements from any combination of the sustainable resources (renewable, hydro and energy efficiency) by 2025. The 15% includes the persistence (life of measures) of programs run in previous years. SRP must meet 5% of retail requirements by 2015. The Board will be revisiting these goals in the Spring of 2011 and open the resolution to public process and comment.

Funding and Policy Approaches to Achieve Increased Savings

Energy efficiency programs offered by investor-owned utilities in Arizona are funded through a systems benefits charge, collected through a non-bypassable surcharge on electricity bills, or through an adjustor mechanism, depending on the utility. A non-bypassable charge is a charge applied to all customer bills in a given region whether they receive service from a local utility or from a competitive supplier. The Consortium for Energy Efficiency reports 2009 electric program budgets totaling $49.2 million, and natural gas program budgets of $4 million.

SRP's programs are funded through an Environmental Cost Adjustment Factor ($/kWh). The company plans on spending approximately $40 million per year on energy efficiency and demand response programs over the next five years.

<u>Decoupling</u>
The ACC recently provided authority for disincentive removal (revenue decoupling) and/or shareholder incentives for natural gas utilities (Docket No. 000009B-09-0428 Decision No. 71855). None of the electric utilities have revenue decoupling.

<u>Shareholder Incentives</u>
APS and TEP have shareholder incentives in place, set at 10% of DSM program net economic benefits and capped at 10% of total DSM expenditures. APS proposed modifying this incentive mechanism in a new rate case filed in 2008, requesting recovery of net lost revenues as well as removal of the cap on the incentive. The cap on the incentive was modified via Settlement Agreement. See ACC Docket No. E-01345A-08-0172, Decision 71448, at page 28 of the agreement, for the new tiered approach.

Administrative and Program Strategies to Achieve Increased Energy Savings

<u>TEP</u>

TEP currently has a residential HVAC program, a Residential Audit and ENERGY STAR program, a full-range commercial program with many different measures, a CFL buydown program, a shade tree program, a low-income weatherization program and a new home construction program.

TEP worked with its stakeholders (cities, counties, SWEEP, large customers, etc.) to get input on its energy efficiency implementation plan. The company continues to work with its measurement and evaluation group to make sure that the programs being proposed make sense for the community.

The company makes sure it gets a good mix of people to work on the programs—both utility staff and the implementation contractors. The philosophy is to hire some people who understand energy efficiency programs and some people who come from different backgrounds that bring their contacts with them. For example, a marketing contractor from the new home sector will contribute to the success of the program through their existing business relationships. TEP works with its trade allies to get feedback on ways to improve its programs.

<u>APS</u>

One of APS' very successful programs is Home Performance with ENERGY STAR. This program includes a whole house check-up for $99 including direct installation of CFLs and an efficient showerhead. The program also offers incentives up to $1000 for air and duct sealing, insulation, etc. Forty percent of participants go on to install larger measures. To date, program participation has surpassed program goals.

APS is partnering with local banks to provide third party financing for energy efficiency measures. Interest rates are between 6.5% and 8%. The banks provide the capital and APS puts up the reserve account.

APS is piloting the OPOWER program. This program allows customers to compare their energy consumption to their neighbors, assists them with setting energy efficiency goals, and informs them of their progress on reaching their goals.

<u>SRP</u>

SRP has a preference for programs with robust and long-lived savings. Powerwise Homes, for example, is a residential new construction program with a 30 year persistence. Comprehensive programs, like Home Performance with ENERGY STAR, are also very important. In this program, a residential customer is offered rebates on multiple measures after receiving a whole house audit.

Fifty-five percent of SRP's total incremental savings comes from its M-Power program. This prepay program, targeted to "credit-challenged" customers and students, provides energy consumption feedback on a display inside the customer's home. The program has over 100,000 participants out of 850,000 residential customers. SRP has determined that this program helps customers save an average of 12% over the company's basic or time of day plans and that 90% of participants are satisfied with the program.

SRP is a member of EPRI and participates in E-source and Chartwell. Employees make a concerted effort to exchange experiences with others on programs that work and programs that do not work. In particular, employees talk to their counterparts at APS. The company has a product development group that is always looking at new programs, ways to overcome adoption barriers, and collaborate to solve problems. SRP also has an internal measurement and evaluation group to provide the company feedback on its programs. The company talks to its customers. The SRP Communications group conducts focus groups. SRP also has a plugged-in panel of about 50 incentivized customers that have agreed to do surveys. This allows the company to get survey results in 2 weeks.

Early Results, Responses, and Outlook

<u>TEP</u>

TEP savings 1% of its retail sales in 2010. In 2011, the company needs to meet the 1.25% energy savings goal.

A large portion of TEP's portfolio comes from lighting. The company is undergoing a risk analysis to see what other end uses are out there that could possibly replace these savings. They are working with Southwest Gas, Unisource Gas, Unisource Electric and APS on this.

On the horizon, Tuscon Electric Power is branching out in several new directions. Among these initiatives under consideration or active development are:

- Evaporative Cooling. In the TEP area, 30% of the homes have evaporative cooling. Weatherization programs do not affect this end use. The company wants to come up with a good evaporative cooling program.
- There are many tele-centers in TEP's service area. The company is looking at offering a program that lends itself to commercial leasing.
- TEP may look at an upstream buy down program model with end uses besides CFLs (like ENERGY STAR appliances). This is a volume-related program that reaches a lot of people.
- The company is looking into a comprehensive behavioral type program—like the Home Energy Report by OPOWER. This is the program that compares a customer to their neighbor.
- TEP is considering in-home energy-use displays—probably combined with a direct load program.
- Direct install program for multifamily residential customers.

The company would like get decoupling and a better performance incentives mechanism.

SRP

SRP is currently exceeding the savings goals of its Sustainability Portfolio Standard. However, the company wants to be realistic about savings expectations—what savings goals can be reached with a reasonable amount of money. Customer satisfaction is a principal goal so it is important that the programs continue to be cost-effective.

SRP is going to focus more on commercial energy efficiency programs. For example, SRP is working on developing specialty programs (compressed air, new construction, metro commission, custom programs, etc.) for commercial customers. The company is also looking at lighting rebates for small business customers.

SRP had a few words of advice:

> "Don't be afraid of trying new approaches; try better, faster, less costly approaches; have an exit strategy if something isn't working; and keep senior management and the Board informed."

References

ACEEE State Energy Efficiency Policy Database http://www.aceee.org/sector/state-policy

Arizona Corporation Commission, Decision No. 71436, Docket No. RE-00000C-09-0427, In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency, Order, December 18, 2009. http://images.edocket.azcc.gov/docketpdf/0000116125.pdf

Arizona Corporation Commission, Decision No. 71448, Docket No. E-01345A-08-0172, In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such, Opinion and Order, December 30, 2009. http://images.edocket.azcc.gov/docketpdf/0000107462.pdf

Arizona Corporation Commission, Decision No. 71819, Docket No. RE-00000C-09-0427, In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency, Opinion and Order, August 10, 2010.http://images.edocket.azcc.gov/docketpdf/0000116125.pdf

Arizona Corporation Commission, Decision No. 71855, Docket No. RG-00000B-09-0428, In the Matter of the Notice of Proposed Rulemaking on Gas Energy Efficiency, Opinion and Order, August 25, 2010. http://images.edocket.azcc.gov/docketpdf/0000116980.pdf

Salt River Project, 2006 Board Resolution http://www.srpnet.com/environment/earthwise/pdfx/spp/2006Final_Resolution_SPPRP.pdf

Salt River Project, Sustaining Our Future, SRP 2010 Sustainability Report Summary http://www.srpnet.com/energy/2010eereport.pdf

Tucson Electric Power Company, ACC Docket No. E-01933A-11-0055, In the Matter of the Application of Tucson Electric Power Company for Approval of its 2011-2012 Energy Efficiency Implementation Plan, January 31, 2011. http://files.shareholder.com/downloads/UNIS/0x0x445924/96a183d2-2521-4f5e-9e6b-9908c72d202b/TEP_s_EE_Plan.pdf

Colorado

Background

Colorado utilities have administered and implemented efficiency programs for their customers for decades, but until recently the overall scope of the portfolios has been modest relative to the top tier of leading states. After the electric utilities spent $15 million on efficiency programs in 1996, Colorado programs were scaled back in the late 1990's, with electric efficiency spending dipping below $3 million in 1998. This was in line with the national trend of reduced efficiency investments corresponding to deregulation and restructuring. The years 2000 to 2005 also had relatively little utility energy efficiency activity in Colorado. During that period Public Service Company of Colorado (PSCo), owned by Xcel Energy, agreed to provide some efficiency programs as part of an agreement that earned them approval to build a coal-fired power plant. In 2004, Colorado ranked 17th among states as ranked by cumulative annual GWh of utility electric savings based on Energy Information Administration data.

Xcel Energy, through their operating subsidiary Public Service Company of Colorado (PSCo), is the largest utility with over 1.3 million customers, two-thirds of the state's retail electric sales, and substantial natural gas sales. Their programs and those of the other investor-owned utilities are funded by a demand-side management Cost Adjustment Mechanism rate rider, also known as a tariff rider. PSCo is allowed to recover the costs for its energy efficiency and demand programs. The second largest electric utility is Colorado Springs Utilities, a municipal utility serving more than 550,000 customers. Statue requires that the Colorado Public Utilities Commission (COPUC) report annual to the state assembly on utility demand side management.

There are five regulated gas utilities: PSCo, Atmos Energy, Black Hills Energy (formerly Aquila), SourceGas, and Eastern Colorado Utility Company. For Colorado natural gas utilities, each utility may recover its program expenditures either through expensing or by adding program expenditures to base rates as a part of, or outside of, a rate case. The gas utilities' overall efficiency budgets had been consistently at or near $2.5 million per year from 2006 to 2008.

As of fall 2009, all Colorado investor-owned gas and electric utilities were implementing PUC-approved energy efficiency programs. PSCo and Black Hills Energy together account for more than 80% of the total projected GWh savings and over 58% of retail electricity sales in the state; municipal utilities and electric co-ops also implement efficiency programs, but make up a smaller proportionate share relative to sales. These projections are under the Colorado Climate Action Plan, an effort to reduce greenhouse gas emissions that relies on energy efficiency to achieve 41% of the emissions reductions.

Prior to the adoption of energy efficiency resource standard policies in 2007, Colorado did not provide alternative business models for regulated utilities, such as revenue decoupling, nor were there shareholder incentive mechanisms for investor-owned utilities.

Colorado's Energy Efficiency Resource Standard Policy

In April 2007, in passing HB-07-1037, the Colorado legislature amended Colorado statutes C.S.R. 40-1-102 and 40-3.2-101-105, requiring the Colorado Public Utilities Commission (COPUC) to establish energy savings goals for electric and gas utilities as well as provide utilities with financial incentives for implementing cost-effective energy-saving programs. The bill requires the COPUC to annually report on the progress made by investor-owned natural gas and electric utilities in meeting their demand side management goals.

The statute does not directly set a fixed schedule of statewide percentages of energy savings to be achieved by particular years, so it is not strictly speaking a resource *standard*. The law does not require the acquisition of all cost-effective energy efficiency resources. Instead it sets an overall multi-year statewide goal for investor-owned utilities of least five percent of the utility's retail MWh energy sales in the base year (2006) to be met by the end of 2018, counting savings in 2018 and including savings from

DSM measures installed starting in 2006. The law empowers COPUC to set interim goals for utilities and to modify goals.

Electric Goals
In a May 2008 decision, the COPUC set energy savings goals for PSCo, superceding the targets established in an earlier Least Cost Planning Settlement, which called for cumulative savings of 800 GWh by the end of 2013.[50] The Commission accepted PSCo's current goals in a Settlement Agreement in Decision R08-1243 in February 2009, which allowed PSCo to amend its original set of goals. The updated goals for 2009 and 2010 were designed to save approximately 0.6% (176 GWh) in 2009 and 0.8% (237 GWh) in 2010, exceeding the mandated savings in both years.[51] It plans to achieve 240 GWh in 2011.[52] PSCo filed new long term savings goals with the Commission in late 2010 that would increase cumulative electric savings for the period between 2009 and 2020 from its original 11.49% goal to 13.61%.[53] These goals are under review by the Commission and some interveners such as the Southwest Energy Efficiency Project (SWEEP) have proposed even higher energy savings and peak demand reduction goals. The Commission is expected to render a decision in this docket by early April.[54]

The Commission accepted a Settlement Agreement in Decision R08-1243 in February 2009 that allowed PSCo to amend its goals. The updated goals for 2009 and 2010 were designed to save over 400 million kWh, or approximately 0.8% in 2009 and 1.0% in 2010, more than the mandated savings for both years.[6] PSCo filed new long-term savings goals with the Commission in late 2010, which would increase cumulative electric savings by 2020 from 11.49% to 13.61%.

Natural Gas Goals
For investor-owned natural gas utilities, the legislation structured the requirement in two parts. First, the natural gas IOUs must set DSM spending targets of more than 0.5% of revenues from customers in the prior year. Then energy savings targets are established by COPUC commensurate with spending and stated in terms of quantity of gas saved per dollar of efficiency program spending.

The legislation directed the COPUC to establish use of a modified total resource cost (TRC) test for evaluating DSM program cost effectiveness. It is considered modified because it includes valuation of emissions reductions.

Table 24: Colorado Natural Gas Energy Savings Targets, 2009-2011

	Savings Target (Dekatherms)		
	2009	2010	2011
Public Service Company of Colorado	318,141	402,808	368,227
Atmos[55]	13,503	19,385	
Black Hills Energy[56]	37,227	48,283	59,302
SourceGas[57]	18,565	23,643	
Eastern Colorado[58]	171	202	

[50] Colorado Public Utilities Commission, Docket Nos. 04A-214E through 216E
[51] Based on 2009 retail sales. Xcel Energy/Public Service Company of Colorado 2009/2010 Demand-Side Management Biennial Plan, Electric and Natural Gas, Docket No. 08A-366EG. Originally filed August 2008, revised February 2009. In this profile, Xcel goals and savings are given at the generator level; these values need to be reduced by about 7% to get savings at the customer level.
[52] PSCo 2011 DSM Plan
[53] Personal Conversation with Deb Sundin, Xcel, 10/27/2010
[54] Docket 10A-554EG
[55] Atmos DSM Plan, pg. 14
[56] Black Hills NG DSM Plan, pgs 69-70. Docket No. 08A-541G
[57] SourceGas DSM Plan, pg. 15
[58] CPUC Docket No. 08A-541G

Funding and Policy Approaches to Achieve Increased Savings

One of primary ways utilities are using to achieve greater energy savings has been to invest more money. Funding for utility energy efficiency has increased rapidly in Colorado under the EERS. According to the revised 2009/2010 Demand-Side Management Biennial Plan, PSCo increased their investment in gas and electric efficiency and demand programs from $63 million in 2009 to $80 million in 2010. Spending on utility natural gas energy efficiency programs was increased from the 2006 to 2008 annual average of $2.5 million to $13 million in 2009 and $18.4 million in 2010.

The Colorado Legislature enacted two laws along with the EERS to align the utility incentive structure—and the business and regulatory model utilities operate in—with achievement of the EERS goals: natural gas decoupling and shareholder incentives for gas and electric utilities.

Decoupling

On June 18, 2007, the Public Utilities Commission approved a partial revenue decoupling adjustment for residential gas customers as part of a three-year pilot program. The proposed mechanism is implemented through a rider applied to the company's base rate gas service revenues to compensate for the prior year's changes in weather-normalized use per customer. This is a three-year pilot program, initially set to run from October 1, 2008 to September 30, 2011. If revenue per residential customer declines more than 1.3% per year, the rate adjustment is updated to recover reduced weather-normalized revenues due to reduced usage per customer. This value (1.3%) was chosen because it equals 1/2 of the historic rate of decline referenced in PSCo's testimony (Docket No.'s: 06S-655G and 08L-413G). Colorado has not implemented decoupling for electric utilities.

Shareholder Incentives

The law gives broad authority to COPUC to allow for "a utility's investments in cost-effective DSM programs to be more profitable to the utility than any other utility investment that is not already subject to special incentives" and instructs COPUC to consider allowing a rate of return on DSM investments higher than on other investments, accelerated depreciation or amortization periods for DSM investment, an incentive to allow the utility to retain a portion of the net economic benefits from a program for shareholders, and an incentive to allow the utility to collect program costs through a cost adjustment clause.

The PUC has implemented a performance-based incentive for PSCo, enabling them earn a return of 0.2-12% of net benefits on its demand-side management expenditures as long as it achieves at least 80% of its energy savings goal in any one year. The incentive is tied to energy savings achieved and the net economic benefits of the programs. The incentive is capped at 20% of PSCo's DSM expenditures. Black Hills Energy has adopted the same mechanism. For natural gas utilities, the incentive bonus is capped at 25% of the expenditures or 20% of the net economic benefits of the DSM programs, whichever amount is lower. For PSCo, the actual award was $9.65 million in 2009, or 17.4% of their $55.45 million in program costs.

Administrative and Program Strategies to Achieve Increased Energy Savings

PSCo has numerous program efforts and enhancements underway to increase energy savings in the near term of one to three years. They have had success with ENERGY STAR New Construction in the Residential sector. PSCo has increased rebates across many programs from 20-25% of the consumer's incremental cost to 40%, and they have begun offering rebates for more products. Also in the Residential sector, PSCo has been running pilot programs for air conditioning, including early retrofits for central air conditioning systems, a tune-up program, and high-performance installation. They are also offering more services, such as small business lighting and process efficiency services. Small business lighting programs in which PSCo hires a lighting auditor for the small business owner have been very successful.

PSCo expects Commercial and Industrial programs to drive most of their energy efficiency, offering a full complement of programs that they describe as among the best in the nation, comparable to those in the Pacific Northwest. These include all the standard prescriptive rebate programs for all the end-uses. They also offer a very robust Custom program for industrial and large commercial customers; if there is no rebate for the measures, the customer many initiate a proposal for what they would like to do.

Xcel Energy has had successful Industrial energy efficiency programs in other states, such as Minnesota. These have included a bundled approach, which includes energy planning. By combining efficiency measures that are not sufficiently cost-effective on their own with measures that do exceed the cost-effectiveness threshold, large projects with large energy savings may be accomplished that otherwise would not. Xcel is replicating this in the Commercial sector through PSCo in Colorado through their Energy Design Assistance Program for large commercial buildings and new office buildings. Savings have increased 50% for a small group of customers. One key is that the annual planning process that has been business as usual is being displaced by a systems thinking approach. PSCo brings in a consultant (Inventa 1 to 5, an Australian company) to work with the customer, who does a facility walk-through, and then develops a three year commitment document. PSCo brings in energy analysis, a Bundle Rebate form, and a bonus financial incentive for the bundled project, and provides project management help. The process helps to build working relationships between Xcel Account Managers and large commercial customers, and to establish multi-year planning as the norm.

Early Results, Responses, and Outlook

With PSCo contributing such a large part of the energy efficiency activity statewide, their success has a major impact on the progress of the state as a whole. Leveraging parent company Xcel Energy's years of program delivery experience in Minnesota, PSCo surpassed their planned 2009 and 2010 electricity savings goal of 175 GWh each year, saving 219 GWh in 2009 and 237 GWh in 2010. For natural gas, Xcel had already budgeted 250% of the minimum spending requirement prior to the EERS, as gas prices had doubled due to suppliers building a pipeline out of the Rocky Mountains. Now that prices have declined again, energy efficiency measures are much less cost effective, many with a total resource cost of 1.1. In 2009, the first EERS year and the first year in which PSCo had a complete and comprehensive efficiency plan in place, savings were 308,761 Dth, or 97% of the goal the Commission-approved plan.

Prognosis

With the aggressive savings increases planned over the next three to four years, PSCo will build on their strong commercial and industrial programs, expanding CFL and Commercial Lighting. By 2014 to 2015, however, there is expected to be a gap between the savings targets and what the current portfolio of traditional programs can deliver. In addition to continuing and expanding existing programs, PSCo will be exploring new directions. Pilot behavioral programs in the Residential Sector are now in the field. Using more customer education and providing more data, these programs give customers more control over their household energy use. As smart grid technologies such as advanced metering infrastructure and others evolve, PSCo may be able to provide features such as two-way communication, specialty rates to incentivize efficiency for customers, and enabling technology by 2014-2015.

References

http://www.utilityexchange.org/colorado/2010-presentations/CUE-Powerpoints/UtilityDSM-InColorado.pdf

Energy Efficiency and Colorado Utilities: How Far We've Come; How Far We Need to Go. DORA, PUC, 10/29/2009

Steven Nadel and Rachel Gold. 2010. "Utility DSM: Off the Coasts and into the Heartland." *Electricity Journal,* October, 23 (8) 51-62. Elsevier Inc.

EERS statute http://www.michie.com/colorado/lpext.dll?f=templates&fn=main-h.htm&cp. 40-3.2-102 to 105

Public Utilities Commission Report to the Colorado General Assembly on Demand Side Management. April 28, 2009. Available at http://www.dora.state.co.us/puc/rulemaking/HB07-1037/HB07-1037StaffDSM04-2809ReportToLegislature.pdf

Colorado Public Utilities Commission. Docket 07A-420E. Decision C08-0560. (June 5, 2008).*In the matter of the application of public service company of Colorado for authority to implement an enhanced demand side management*

program and to revise its demand-side management cost adjustment mechanism to include current cost recovery and incentives. http://www.dora.state.co.us/PUC/DocketsDecisions/decisions/2008/C08-0560_07A-420E.doc

Docket 08A-518E, Decision No. R09-0542,COPUC Docket No. 08A-518E

Public Utilities Commission Report to the Colorado General Assembly on Demand Side Management. April 28, 2009. http://www.dora.state.co.us/puc/rulemaking/HB07-1037/HB07-1037StaffDSM04-28-09ReportToLegislature.pdf

Xcel Energy/Public Service Company of Colorado 2009/2010 Demand-Side Management Biennial Plan, Electric and Natural Gas, Docket No. 08A-366EG. Originally filed August 2008, revised February 2009. http://www.xcelenergy.com/staticfiles/xe/Regulatory/DSMBiennialPlan_ExecutiveSummary.pdf

Pennsylvania

Background

Pennsylvania is in the process of ramping up from virtually no efficiency programs at all to a major, multi-sector portfolio within three years. This is one of the fastest expansions of any state in the country. Before Act 129, Pennsylvania had Four Sustainable Energy Funds that had been created as a result of individual settlements with the state's five major distribution utilities to promote both renewable energy and energy efficiency. In 2007, approximately $6.5 million was distributed in the form of loans and $2 million was provided in grants from all SEF's. West Penn Power SEF is the only fund still collecting funds through distribution and transmission rates, currently at $0.001/kWh. With the implementation of Act 129, utilities will spend hundreds of millions in three years.

According to the Energy Information Administration, Pennsylvania utilities reported efficiency program savings of 2,715 MWh in 2008, less than 0.01% of total retail sales. This number is improving dramatically as the state ramps up its energy efficiency efforts.

Of the eleven electric utilities, there are seven major companies, and the largest of those are First Energy, Philadelphia Electric Company (PECO) and Pennsylvania Power and Light (PP&L) as shown in table XX below. First Energy Corporation acquired Allegheny earlier in 2011 and will operate it under the operating company West Penn Power. First Energy also owns Pennsylvania Power and Pennsylvania Electric.

Table 25: Largest Electric Operating Utilities in Pennsylvania

Utility (Parent Company)	2009 Retail MWh sales (1,000's)	Planned MWh savings (1,000's)	Percent Planned 3-year Savings
PECO (Exelon)	37,723	1295	3.43%
Allegheny (First Energy)	NA	646	NA
PP&L	36,659	1362	3.72%
Duquesne	NA	576	NA
Penn Power (First Energy)	2,063	146	7.08%
Metropolitan Edison	13,481	448	3.32%
Pennelec (First Energy)	13,090	447	3.41%

For this case study, we only conducted one interview. The emphasis on PECO is only to provide an example case and is not meant to be representative of other electric distribution utilities.

Regulatory Policies

Pennsylvania does not have any policy that decouples utility profits from sales volume and no policy that rewards successful energy efficiency programs through shareholder incentives.

Pennsylvania's Energy Efficiency Resource Standard Policy

Act 129, passed in October 2008, established an energy efficiency resource standard in Pennsylvania. Each electric distribution company (EDC) with at least 100,000 customers must reduce energy consumption by a minimum 1% by May 31, 2011, increasing to 3% by May 31, 2013.[59] Peak demand must be reduced by 4.5% by May 31, 2013. PECO's share of the statewide goal translates to 394,000 MWh by 5/31/11 and 1.2 million MWh by 2013. The percentage consumption reductions are solely applicable to the seven EDC's, not relative to total state electric use. Less than 5% of savings were planned to come from non-program sources including conservation voltage reduction, distributed resources, and energy savings resulting from time-of-use rates.

Ten percent of both consumption are to come from federal, state, and local government, including municipalities, school districts, institutions of higher education and nonprofit entities. The PUC must also set targets for the period beyond 2013. Failure to achieve the reductions required (load and/or peak demand) subject the EDC to a civil penalty of not less than $1M and not to exceed $20M.

Under the new legislation, the electric distribution companies' energy efficiency and conservation plans have a cost-recovery tariff mechanism to fund the energy efficiency and conservation measures and to ensure recovery of reasonable costs. The utilities can also recover the costs through a reconcilable adjustment mechanism. This will bring in over $200 million per year by 2011. However, the law also institutes an annual spending cap of 2% of the total annual EDC revenues as of December 31, 2006 for Energy Efficiency and Conservation (EE&C) programs.

There is no natural gas EERS in Pennsylvania.

Programs and portfolios must have a benefit cost ratio greater than 1.0 as measured by the Total Resource Cost Test. Evaluation, measurement, and verification are done through a statewide evaluator. The statewide process was initiated in September, 2009 by GDS Associates, Inc., Nexant and Mondre Energy are also on the evaluation team.

Penalties

Pennsylvania has no "carrots" such as performance incentives or shareholder incentives to reward successful energy-saving on the part of the utilities, but the state does have strong "sticks" in the form of financial penalties. This is an uncommon policy among states with energy efficiency resource standards. Utilities face civil penalties starting at $1 million and going up to $20 million if they do not meet targets by May 31, 2011 and May 31, 2013.

Funding and Policy Approaches to Achieve Increased Savings

In October 2009, the PUC approved Energy Efficiency and Conservation (EE&C) plans for the seven electric distribution companies covered under Act 129.[60] The PUC supported the utilities in meeting extremely aggressive and rapid efficiency goals by allowing flexibility in the design of the EE&C plans, setting rules that allowed EDC's to craft plans that would work for their service territory and customers.

Funding is prerequisite to succeeding in the accelerated development of comprehensive energy efficiency program portfolios. Pennsylvania had the third largest absolute growth in electric efficiency program budgets of any state from 2009 to 2010, rocketing from $1 million to $151 million[61]. Only New York and California increased budgets more.

Administrative and Program Strategies to Achieve Increased Energy Savings

[59] Implementation Order http://www.puc.state.pa.us/electric/pdf/Act129/EEC_Implementation_Order.pdf
[60] http://www.puc.state.pa.us/general/publications_reports/pdf/09-10_PUC_Ann_Rpt.pdf
[61] State of the Efficiency Program Industry: Expenditures, Impacts & 2010 Budgets, Consortium for Energy Efficiency.

The utilities' planned allocation of program budget funds and expected savings from residential and business sectors varied widely. Met Ed and Penelec committed 50% and 43% of their EE&C Plan funding to residential. Both expect over 46% of plan benefits to come from these residential programs. Duquesne, Allegheny and PPL budgeted the most for commercial and industrial programs, and committed only 29% to 39% of EE&C Plan funds to residential.

PECO began the first program year with a portfolio of programs for electric customers. The company combined program introduction with trade ally outreach to make sure the market was aware and to prepare contractors for informing customers about the energy efficiency offerings available. PECO initiated an awareness campaign for their Smart Ideas brand with advertisements and outreach through a diverse array of media including television, radio, billboards, magazines, bill inserts, programmatic events such as community seminars and tabling talks.

After the initial rollout, more measures were added to the programs for commercial and industrial customers. Efficient televisions were added in the residential sector. PECO also revised incentive levels. In order to get more immediate savings, they will be shifting more money into the CFL program, and cut funds flowing to Residential New Construction and Residential Whole Home Performance (comparable to Home Performance with ENERGY STAR).

The PUC created a registry of qualified Conservation Service Providers (CSP's). Each utility EE&C plan must include a contact with at least one CSP to implement at least part of their programs.

PECO's structure for energy efficiency relies heavily on implementation contractors, one for each program or area. Jayco is the contractor for refrigerator pick-up and recycling, ECOS implements CFL and Smart Home rebates, and Navigant Consulting does evaluation, working closely with the statewide evaluator hired by the PUC. For initial energy efficiency plan development, PECO worked with outside consultant Global Energy Partners.

Early Results, Responses, and Outlook

Pennsylvania utilities officially began implementing programs counting towards their EERS on June 1, 2009. Because EE&C plans were not approved until October, there was some delay for utilities to implement programs. So far, there has been a major discrepancy between the performance of major utilities (PECO, PPL) and that of smaller utilities with less experience implementing efficiency programs. The 1st quarter report of Program Year (PY) 2 seems to indicate, however, that all of Pennsylvania's utilities are now achieving significant savings levels, which may put the state on track towards meeting their EERS goals.[62] In the cases of Allegheny, Met-Ed, and Penelec, savings in the 1st quarter of Program Year 2 exceeded all of those of PY 1. Twenty-seven programs began in the 1st quarter of PY 2, compared to 38 initiated in all of PY 1.

[62] Pennsylvania has a Statewide Evaluator, which reports on implementation status quarterly. As of the drafting of this report, the latest confirmed savings data comes from Program Year 2 (2010-2011) 1st Quarter Report.

Table 26: Pennsylvania Energy Savings as Percent of Targets 2011-2013

Program Administrator	Percent of 2011 Target Achieved end of PY 1	Percent of 2011 Target Achieved end of 1st Quarter, PY 2	Percent of 2013 Target Achieved
Allegheny	1.4%	8.9%	0.50%
Duquesne	19.0%	33.0%	11.0%
Met-Ed	8.2%	18.7%	6.2%
Penelec	8.9%	25.5%	8.5%
West Penn Power	11.7%	22.5%	7.5%
PECO	40.0%	83.0%	28.0%
PPL	22.0%	39.0%	13.0%
STATEWIDE	**19.0%**	**38.54%**	**12.85%**

PECO customers responded overwhelmingly to initial program offerings, which were done on an appliance-by-appliance basis for dishwashers, refrigerators, air conditioners, heat pumps, dehumidifiers, and others. In order to stay within budget, they reduced rebate levels.

Early lessons learned from PECO highlight that it is important to:

- have the evaluation, measurement, and verification provider and the database for savings and project tracking in place before programs are rolled out.
- ensure that the Commission is in alignment with the Statewide Evaluator on how savings projections will be made and the assumptions going into the savings claim. Elements such as measure lives, M&V protocols, the technical resource manual and sampling plans should be agreed on.
- stay in close, frequent communication with implementation vendors on a daily basis concerning customer experience, timelines, and management.

Prognosis

In 2010, PECO had exceeded the first savings checkpoint. A PECO representative expressed "absolute 100% confidence" that they will continue to meet their energy savings objectives for total MWh. In 2009, they expected to exceed targets by 50% in 2010 and by 10% Program Year 2012, a cumulative savings of 1.3 billion kWh. Government and non-profits had been moving slower due to budget issues. PECO is addressing this with special outreach.

At PECO, market transformation has been discussed, however, they have not set specific objectives in that area. PECO operates their energy efficiency programs in the context of their three-year goal, whereas market transformation requires a long-term perspective. Statewide, this emphasis on hitting annual and three year is encouraged in Act 129, which asks the Public Utilities Commission to assess the first four years of programs (2009 to 2012).

References

Pennsylvania Public Utility Commission. 2011. *Pennsylvania Public Utility 2009-10 Annual Report* http://www.puc.state.pa.us/general/publications_reports/publications_reports_yearly.aspx

Illinois

Background

Prior to legislation passed in 2007, there was limited funding and little associated utility energy efficiency administration infrastructure in Illinois. The state had minimal involvement with utility energy efficiency programs, other than a small annual funding requirement (~ $3 million/year) created in the Illinois restructuring legislation (HB262) in 1997 to support some small programs administered by the state Department of Commerce and Economic Opportunity (DCEO).

Commonwealth Edison (ComEd) and Ameren Illinois Utilities (Ameren Illinois) are the largest electric utilities in Illinois. ComEd service territory covers most of northern Illinois, overlapping with Nicor Gas across northernmost third of the state, except for the City of Chicago, which is served by Peoples Gas, and Integra company. Integra also owns North Shore. Ameren Illinois is comprised of Illinois Power, Central Illinois Public Service, and Central Illinois Light Company. Ameren Illinois is also the third largest Illinois natural gas distribution company by number of customers.

Illinois Energy Efficiency Resource Standard Policy

The scope of energy efficiency activity began a dramatic expansion in July 2007, when the Illinois legislature passed the Illinois Power Agency Act (IPAA), which includes requirements for energy efficiency and demand response programs. Under the new law, utilities, with help from the Illinois Department of Commerce and Economic Opportunity (IDCEO), are directed to implement cost-effective energy efficiency programs and measures sufficient to achieve annual energy savings in order to reduce direct and indirect costs to consumers. The targets of Public Act 095-0481 are 0.2% of energy delivered in 2008, increasing by 0.2% per year until 2012 and increasing 0.4% from 2012 until 2014 and reaching 2% savings in 2015.

SB1592 authorized utilities to recover the costs for providing energy efficiency programs and directs utilities to design and implement cost-recovery tariffs. Funds from the tariffs cover both utility- and state-administered programs. These are referred to as Energy Efficiency Plan (EEP) charges.

Savings may be accomplished by avoiding or delaying the need for new generation, transmission, and distribution infrastructure. Because Illinois is still technically a "restructured" state—with distribution utilities purchasing power in competitive wholesale markets, it is not clear how energy efficiency would be factored into resource planning decisions. Customers also purchase power directly from Retail Electric Suppliers (RES).

Individual electric utilities are required to administer 75% of the total energy efficiency program funds. The Illinois Department of Commerce and Economic Opportunity (IDCEO) administers 25% of the funds, which are used to for efficiency programs serving government facilities, low-income households, and market transformation-oriented information and training programs. In 2008, Illinois set up requirements for natural gas energy efficiency programs.

Rate Cap and Penalty

The total charge to customers is limited to 0.5% of their total rate base in year one. The cost increases year until it reaches 2.0% per year in 2015. If, after 2 years, an electric utility fails to meet the efficiency standard it must make a contribution to the Low-Income Home Energy Assistance Program. The combined total liability for failure to meet the goal shall be $1,000,000, which is assessed as follows: a large electric utility such as ComEd shall pay $665,000, and a medium electric utility shall pay $335,000. A large electric utility is an electric utility that, on December 31, 2005, served more than 2,000,000 electric customers in Illinois while a medium electric utility served 2,000,000 or fewer but more than 100,000 electric customers in Illinois on December 31, 2005. If a utility fails to meet their goals (or modified goals), then programs could be transferred to the Illinois Power Authority. Utilities have expressed concern that the if that were to happen then the programs might not be deployed as effectively for customer benefit.

Illinois established a natural gas EERS in SB 1918 establishes a natural gas savings target that begins with 0.2% savings by May 31, 2011 and ramps up to 1.5% in 2019, providing cumulative savings of 8.6% in 2020. For all programs, there is a rate impact cap of 2% of overall rates over the three-year reporting period.

Decoupling
In February 2008, North Shore Gas and Peoples Gas and Coke were both approved for four-year revenue-per-customer decoupling pilots. Monthly adjustments began in March 2008. To continue the program after four years, the utility must make a general rate filing in which the commission extends the program. (Cases 07-0241/07-0242 (consolidated) and 09-0166/09-0167 (consolidated)). Electric utilities are not authorized for decoupling or lost revenue recovery.

Shareholder Incentives
Illinois does not have a mechanism in place for utility shareholder incentives for energy efficiency. SB1592 does not address the issue

Under the EEPS, cost-effectiveness is determined at the measure level using the Total Resource Cost (TRC) test. Duel-fuel utilities such as Ameren Illinois are permitted to count the avoided costs of both gas and electric energy impacts from each measure. The law requires that the benefit cost ratio using the TRC be greater than 1.0 in the annual filings, which are done after the program evaluation reports are completed, and which are calculated using net energy savings, not gross.

The energy savings goals are net savings overall: every efficiency program is evaluated for impact. Utility representatives state that how to use net-to-gross is not explicit in the law. Whether prescriptive values for net savings are set in advance versus measured retrospectively—through impact evaluation–has important implications for program design. Ameren Illinois has argued that retrospective application of net-to-gross will result in lower savings attribution for their CFL programs.

Funding and Policy Approaches to Achieve Increased Savings

Massive budget increases for energy efficiency programs have paved the way for comprehensive energy efficiency portfolios to be developed and stepped-up annual energy savings goals to be realized. Funding for electric efficiency programs shot up from less than one million in 2007 to $89.9 million in 2009 and then to $107.4 million for 2010. Natural gas efficiency budgets went from zero in 2007 to over $4 million in 2009.

Table 26: Electric Energy Efficiency Spending

2006	2007	2008	2009	2010 (budget)
$3,222	$829	$8,818	$89,900	$107,400

ComEd alone reported spending $37 million on efficiency in 2009; their budget for 2010 more than doubled, to $81.8 million. Of that, $18.2 million was for general portfolio costs, such as education, administration, R&D, and on-line tools.

The Illinois Energy Efficiency Stakeholder Advisory Group (ILSAG) was established by the Illinois Commerce Commission to review progress toward achieving the electric energy efficiency goals and to strengthen the large-utility efficiency program portfolios (ComEd, Ameren Illinois) and IDCEO's portfolio. Several major environmental and consumer groups meet along with state and utility representatives. ILSAG is highly regarded as a very good stakeholder group engaging in healthy dialog each month and having a lot of positives in the structure.

Administrative and Program Strategies to Achieve Increased Energy Savings

ComEd acquires more than 70% of their electric savings from lighting programs. This portfolio design was a response to the combined effect of the policy requirement placed on them, to develop and expand energy saved rapidly, cost-effectively, and within the cost cap. They are doing a pilot program for midstream CFL rebates, increasing market segmentation to add in nontraditional segments, and adding in program elements such as commercial real estate. A ComEd cross-cutting effort to obtain higher energy savings is underway to clean their project tracking and reporting data to improve data management.

For residential programs, early evaluation of the air conditioning measures included in their programs were deemed to save significantly less savings than planned due to the Illinois climate and the discretionary nature of customer cooling habits. ComEd has struggled to find measures that meet the cost-effectiveness test. They are exploring new measures and incentives mechanisms such an HVAC equipment early retirement, and customer based incentive features. The largest and most successful program is ENERGY STAR Lighting, which has been providing nine million bulbs per year. Since June, 2010, ComEd has been doing joint residential pilot programs with the gas utilities as an addition to their residential direct install programs. Multifamily has been up and running and they have completed 15,000 units. ComEd plans to complete another 15,000 units of multi-family direct installations by June, 2011. Similarly, single family retrofits are highlighting the cost effectiveness issue with insulation measures for reducing cooling costs (electric avoided costs). For avoided air conditioning energy use, the cost of saved energy could approach a $1 per kWh, which is almost 4 times the average cost per kWh for their portfolio. Given that the potential savings from these retrofit-type programs are in heating (which is mostly provided by natural gas systems), ComEd is working closely with the gas IOUs to deliver these programs jointly and to allocate program costs equitably.

Ameren Illinois does more Home Performance with ENERGY STAR projects in proportion to their size compared with ComEd because they provide both natural gas and electric services to their customers. 40% of Ameren Illinois's customers are in the St. Louis area where electric space heat, air conditioning, and electric heat pumps are more prevalent, which acts to reduce the cost-effectiveness of single family retrofits. According to the Illinois Power Agency Act, savings counted toward the EEPS goals are first year savings, not lifetime savings, which gives utilities an incentive to design their energy efficiency portfolios and programs to maximize short-term savings rather than overall savings.

Ameren Illinois also has a major emphasis on lighting programs, although they have significantly decreased plans for CFLs from 3 million to 500,000 due to how kWh savings are attributed. Ameren Illinois does not have a stipulation with the ICC to make adjustments to attribution, and CFLs savings are not deemed to be a set amount of kWh per bulb in advance. Instead of including the additional CFLs in their program plans, they are shifting more program resources to provide upstream rebates for high performance T-8 bulbs and high efficiency motors for commercial and industrial customers.

Early Results, Responses, and Outlook

Results to date among the major program administrators in Illinois have been mixed.

Table 27: Illinois Electric Efficiency Savings 2008-2010

Utility	**2008-2009 (PY 1) Requirement (MWh)**	**2009 Achieved (MWh)**	**Percent Attained**	**2009-2010 (PY 2) Requirement (MWh)**	**2010 Achieved (MWh)**	**Percent Attained**
ComEd	148,842	**163,717**	110%	315,223	**456,151**	145%
Ameren Illinois	62,808	**89,955**	143%	118,288	**142,995**	121%
DCEO	54,572	**27,285**	50%	110,715	**72,331**	65%

Sources: ComEd Year 1 Evaluation Report; ComEd Year 2 Evaluation Report; Ameren Illinois Year 1 Annual Report; Ameren Illinois Final PY2 Monthly Report September 2010; DCEO Program Year 2 Evaluation

ComEd savings in Year 3 have not materialized easily, which represents a major change from the first year, which was oversubscribed and under-funded to meet pent-up demand for energy-efficiency program services. Average business sector project size has been shrinking, from $16,000 to $9,000 and then to $5,000 in spite of incentive budgets increasing every year. In response, ComEd has been increasing incentives for replacing T-12 bulbs with high performance T-8 bulbs, for occupancy sensors, and for de-lamping T-12 fixtures from 3-lamp to 2-lamp. They have also increased bonuses to contractors for larger projects and taken out full-page print advertisements in trade publications to promote programs to contractors.

Ameren Illinois has been meeting their goals so far, exceeding the Year 1 goal of 0.2%, meeting the Year 2 goal of 0.4%, and on track to surpass the goal of 0.6% in Year 3. They attribute the savings increases to the economic rebound, to incentives paid to the community of energy efficiency contractors, and to the success of Building Performance Institute (BPI) training in increasing the number of certified contractors eligible to participate in the programs. Previously there had only been nine qualified contractors available over a service territory of 44,000 square miles.

IDCEO did not meet their savings goals, which were triple the percentage of the utilities in the first year, at 0.6% compared with 0.2%. There have been several forces working against realizing savings goals. These included the overall lagging effects of the economy and the recession's effect on government and school budgets; a prior agreement that market transformation activities such as training for contractors and technical assistance did not count for any savings during the first three years; and public entities that are IDCEO's efficiency customers also require substantial technical assistance with completing paperwork which increases the administrative costs of running the programs. Another important issue for IDCEO is that the independent evaluation companies use the same methods to attribute savings for government agencies as for investor-owned utilities. The resulting blended realization rate/net-to-gross ratio for IDCEO electric energy efficiency programs was 36%. Of particular concern is that the baseline energy efficiency is too restrictive. For example, a state correctional facility may be 20 years beyond its estimated useful life, and only a fraction of the actual energy savings for appliances, motors, and other measures are credited to the program. Yet another impediment to increased savings has been the impact of federal energy efficiency funds used by municipalities, which supplanted, rather than supplemented the state government programs.

In response to these challenges, IDCEO has adopted some new approaches. They have hired more contractors to assist government agency customers with paperwork and moving through the process. They are doing more direct partnering, such as with the Community Colleges and Illinois Green Economy Network, who administer a technical assistance program. IDCEO is also working directly with the State Board of Education to promote IDCEO energy efficiency programs, and with Regional Planning Agencies who are helping to administer Energy Efficiency Community Block Grants (EECBG).

ComEd continues to find great potential in lighting-oriented programs to get savings and sees efficiency opportunities persisting in the business sector, such as in warehouses and light manufacturing. Because Chicago has been a freight center for the entire country for a long time, there are many buildings with old, inefficient lights in them. ComEd has 300,000 business customers. For Year 4, ComEd is engaging with more of these businesses to pave the way for increasing participation in large custom programs such as high speed drives and HVAC, which will be a major focus as the percentage savings available from lighting opportunities diminishes overall.

<u>Prognosis</u>
All the major program administrators agree that when the spending caps are reached, the annual savings goals will not be met. The spending limit stays fixed after it reaches 2%, but the MWh requirements increase. In the long term, all the program administrators agree that new funding will be required and that there will be an effort to raise the spending limits. Environmental and consumer stakeholders assert that annual savings above 1% can be reached and sustained statewide and they want to increase the rate cap as well. There are still funds for natural gas efficiency available from Year 1 which stakeholders advocate using. The focus is on the first three years—one utility representative shared that Year 4 was the farthest into the future for which they have discussed plans.

Michigan

Background

Under a progressive Republican Governor in the late 1970s, Michigan became one of the first states to initiate utility energy "conservation" programs (as they were then referred to) in response to the natural gas crisis. By the mid-1990s, Michigan had substantial utility energy efficiency programs, with electric utilities reporting a cumulative annual savings of 770 GWh. In 1995, under a conservative governor, demand-side management and integrated resource planning were discontinued during the move toward electric restructuring. That remained the situation until 2008.

The largest electric utilities are Detroit Edison, owned by DTE Energy, and Consumers Energy, making up over 80% of the retail electric sales. Consumers Energy is also one of the largest natural gas utilities. With Michigan Consolidated Gas Company (MichCon), owned by DTE Energy, they provide the majority of gas service in the state. SEMCO Energy Gas Company and Michigan Gas Utilities Corporation serve almost all of the remaining 15% of gas customers. Including smaller investor owned utilities, electric cooperatives, and publicly owned utilities, there are 66 utilities in Michigan.

In 2006 and 2007, Michigan electric utilities did not report any savings to the Energy Information Administration. In 2007 there was no reported spending on electric or natural gas efficiency programs.

Michigan's Energy Efficiency Portfolio Standard Policy

This changed beginning in October 2008, when the Clean, Efficient, and Renewable Energy Act was signed into law, requiring all types of electric and natural gas utilities to provide "Energy Optimization Programs". Electric utilities were mandated to achieve 0.3% savings in 2009; 0.5% in 2010; 0.75% in 2011; and 1.0% in 2012 and each year thereafter. Percentages are savings relative to the prior year's total retail electricity sales. Natural gas utilities must achieve 0.1% savings in 2009; 0.25% in 2010; 0.5% in 2011; and 0.75% in 2012 and each year thereafter. Percentages are of the prior year's total annual retail natural gas sales in decatherms or equivalent MCFs. For the first triennial cycle, the Michigan Public Service Commission (MPSC) projected electric energy savings targets to be[63]:

2009	0.3%	326,056 MWh
2010	0.5%	502,797 MWh
2011	0.75%	742,451 MWh
Total	1.55%	1,551,317 MWh

Regulated investor-owned utilities are responsible for 88.9 percent of the statewide electric savings targets; municipal utilities represent 7.8 percent of savings; and electric cooperatives, 3.4 percent. Most efficiency programs are administered by the utilities, although some fund a state program. The utilities contract out program implementation. Large electric customers, as determined by their peak use, may administer their own programs.

Another provision of the Act requires the MPSC to submit reports annually each November to the standing energy- and environment-related committees of state house and senate on efforts to "implement energy conservation and energy efficiency programs or measures." At the same time the EEPS was passed, the state legislature also enacted HB 5524, which created, and mandated that utilities participate in, an Integrated Resource Planning process.

There are limits to how much each utility many collect and spend on energy efficiency programs. In 2011, that spending cap is 1.5% of total retail sales revenues for 2009. In 2012 and thereafter, the spending cap is 2.0% of the total retail sales revenues for the two years preceding.

All 66 utilities propose Energy Optimization Plans to the MPSC. To approve a plan, the Commission must determine that the plan is cost-effective and is reasonable and prudent. Cost-effectiveness is measured by the results of the Utility Cost Test ("UCT").

A utility's compliance with the EEPS is based on verified gross savings for the first two years the EEPS is in effect. For the third year, the MPSC regulations require that net savings as determined by an independent third-party evaluation consultant though an impact evaluation must be used.

[63] Report on the Implementation of P.A. 295 Utility Energy Optimization Programs, Revised January 2011. Michigan Public Service Commission. Page 8. http://www.michigan.gov/documents/mpsc/eo_legislature_report2010_339568_7.pdf

The policy framework is structured to remove barriers to and motivate utilities to achieve successful programs through provisions that authorize decoupling and shareholder incentives.

Decoupling
The EEPS statute mandates that the Commission consider decoupling mechanisms proposed by the state's electric utilities. Consumers Energy has included a decoupling proposal in a rate case currently before the Commission (U-15768). Detroit Edison's proposal for a revenue decoupling mechanism was approved by the Commission in January 2010 (U-15751). The Act also authorized natural gas decoupling, which has been implemented in a series of Commission orders. The Commission has approved natural gas decoupling for Michigan Consolidated Gas Company (Docket No. U-15985), for Consumers Energy (Docket No.U-15986), and for Michigan Gas Utilities (U-15990).

Shareholder Incentives
The law also contains two provisions whereby utilities can receive an economic incentive for implementing energy efficiency programs. First, they are allowed to request that energy efficiency program costs be capitalized and earn a normal rate of return. Second, they are allowed to request a performance incentive for shareholders if the utilities exceed the annual energy savings target. Performance incentives cannot exceed 15% of the total cost of the energy efficiency programs. The Commission has approved performance incentives for DTE Energy, which follows the 15% cap authorized in PA 295 (U-15806).

Funding and Policy Approaches to Achieve Increased Savings

In June, 2009, under Orders from the Commission (in cases U-15805 and U-15806), the MPSC staff started a statewide Energy Optimization Collaborative with the mandatory participation of all gas and electric providers. The purpose of the Collaborative is to review and improve Energy Optimization plans to maximize their effectiveness. A variety of other stakeholders were invited to join, and the order stated that energy efficiency experts, equipment installers, and other interested stakeholders should be encouraged to participate. The same day, DTE Energy announced their comprehensive gas and electric program offerings under the Your Energy Savings brand.

Planning, designing and launching efficiency programs as quickly as possible has been a major consideration for utilities as they had a matter of months from the MPSC Energy Optimization Plan Order to begin. DTE was launching programs within six month of when they filed their plan with MPSC.

Funding for gas and electric utility energy efficiency programs has exploded since the passage of the EEPS from nothing in 2007, to $14 million spent in 2008, over $80 million budgeted for 2009, as reported to the Consortium for Energy Efficiency and the Energy Information Administration. By 2012, approved Energy Optimization plans for DTE Energy, Consumers Energy, and MichCon, spending reaches $220 million per year—the maximum allowed—and stays there for the next three years.

Consumer's Energy has been using a policy provision in the EEPS that allows for funding of up to 5% of a utility's energy optimization budget for pilot projects, which gives them the freedom to explore new technologies and delivery approaches with less risk. They are starting to consider working with OPower to provide energy use comparisons for residential customers, for example. Also, for business customers, they are looking at new technologies and programs that have energy saving potential, such as Building Operator Certification (BOC) training for facility managers and a business new construction pilot. A Consumers Energy representative also cited the Energy Optimization Collaborative as a resource for program implementation and design assistance, providing design improvements in addition to those suggested by trade allies. The environmental agencies also provide feedback and have new ideas.

Detroit Edison proposed joint administration of their electric efficiency programs with the Michigan Consolidated Gas Company's natural gas efficiency programs by establishing a combined organization to administer both.

Administrative and Program Strategies to Achieve Increased Energy Savings

In 2009-2010 the utilities stuck to the low-hanging fruit, with lighting programs getting the most emphasis, although there has been some concern about meeting goals in the future with continued reliance on lighting. At the broadest level, one idea that has been considered is the whole-house approach, and a PSC representative related that the utilities are discussing using a holistic approach to commercial efficiency programs as well. On the gas side, there has been more focus on replacing equipment such as furnaces. Gas utilities were not as concerned about meeting savings goals, which were very low in the first years. However, because appliance standards are increasing while annual energy savings requirements are going up, compliance with the EEPS goals will become more challenging in the next few years.

Detroit Edison's approved EO plan holds the allocation of funds constant sectors through 2015, at 45% commercial and industrial and 55% residential.

Consumers Energy efficiency program objectives have not been limited to obtaining MWh and therm savings goals directly. Their aims have been to provide "tried-and-true" programs that provide participation opportunities for all customers, to maximize coordination with other companies, and to invest in Michigan and grow the economy. Consumers Energy continues to employ efficiency program staff with experience from 15 years ago when the utility offered programs, many of whom were selected to work on the current programs. This provides a big advantage because they have a basic experience base with the successful program model used in the early 1990's, with a definite focus on training and working with their trade allies.

Consumers Energy's main portfolio design strategy was to feature programs that had been proven in other jurisdictions, working with contractors to help to develop those programs, and carefully selecting only contractors with established procedures in place, experience with both planning and implementation, and who were effective in duplicating successful program models from other states into Consumers Energy's service territory. The design team included Summit Blue and the Wisconsin Energy Conservation Corporation (WECC). These two companies provided a blend of practical implementation experience (WECC) and theoretical, planning and modeling experience (Summit Blue).

They are coordinating, to the extent possible, with other programs offered around the state. Early on Consumers Energy met with DTE and the Lansing Board of Water and Light. In 2010 they did a joint thermostat installation program with the Board of Water and Light. Both companies split the cost for the installation contractor. Consumers Energy claimed the gas savings and BWL took the electric. In 2011, Consumers Energy will be looking at how to go into a customer's premise and effectively offer joint services. So when a consumer receives electric and gas from different companies they can optimize both companies' efforts.

Consumers Energy's primary residential and business programs demonstrate their focus on proven program approaches.

<u>Residential Programs and Approaches</u>

Upstream Lighting—This CFL buy-down program with amounts negotiated up-front with manufacturers and retailers enables customers to get an "instant rebate" at point-of-purchase and only pay $0.99 per bulb.

Furnace and Central Air Conditioning Rebate—Consumers Energy and their implementation contractors developed a list of trade allies and provided a general training session on the about the programs and how to assist their customers to complete applications. In 2009, our HVAC program had very high participation rates. HVAC trade allies had been experiencing reduced demand for their services due to the recession and were very motivated to participate.

Multifamily Direct Install—Direct installation of energy efficiency measures provides a higher level of certainty that energy savings will be achieved.

Appliance Recycling—After an initial pilot program in a limited area demonstrated its effectiveness, Appliance Recycling was successfully rolled out statewide.

Income-qualified Weatherization—Initially Consumers Energy established a working relationship with the Michigan Community Action Agencies (MCAA) to implement the program, however, because of the time it took to gain alignment and operational efficiencies, some areas of the state were assigned to a different contractor team.

<u>Business Programs and Approaches</u>

Consumers Energy worked closely with trade allies, especially with the lighting and HVAC rebate programs, to provide them with efficiency program knowledge to support and leverage their marketing efforts. One of the stated goals of PA 295 was economic development. Programs were designed to support the trade allies instead of competing with them. As with the residential trade allies, training sessions were provided about the energy efficiency programs. Many of the rebated program measures are purchased at the time of replacement—the trade allies are there with the customers when the measures need to be replaced, but program administrators are not.

Business programs are focused on lighting, primarily because the fast payback on lighting efficiency measures is important to business customers, the lighting trade allies are very active, and there is savings potential in energy efficiency lighting opportunities.

DTE Energy rolled out a fleet of proven residential efficiency programs as well, including ENERGY STAR CFL lighting programs through large retailers, rebates for efficient appliances, home weatherization with incentives up to $1300 per home, incentives for home energy audits, residential direct install, online audit, and others. DTE Energy offered an HVAC program at the end of 2009 and the beginning of 2010 that was wildly successful due in part to contractors' aggressive sales of efficient furnaces. This was launched again in November, 2010.

DTE is also partnering with Masco to run a turn-key program offering "whole home" project rebates. An audit is done and then auditor shows customer paybacks for doing the measures. Customers are seeing 20%-25% modeled energy savings. However, the rate of adoption is not high because the financial commitment is high, and the customer must do at least two of the suggested measures.

DTE energy has also been adding programs on the business side targeting particular markets and market segments. Late last year they piloted a program with small grocery stores in Detroit, in which they did audits and identified measures that were specific to the grocery industry and set up special incentives for them. It was very popular and the funding for these customized incentives ran out in one month. Now they are focusing on hotels and other segments and offering incentives specific to those industries.

Early Results, Responses, and Outlook

Consumers Energy has been surpassing their energy savings goals for both natural gas efficiency program and electric programs. In 2009 their electric target was 108 GWh, and they delivered savings of over 145 GWh. The 2009 natural gas savings goal was 299,623 MCF and their combined program savings was 396,783 MCF.

In 2009 DTE exceeded electric savings requirement of 160 GWh by 39%, saving 203 GWh. Most of the variance from plan was their ENERGY STAR Products Program, which makes up the largest fraction of total savings of any program. The second largest program in terms of savings was C&I Prescriptive.

According to an MPSC representative, in 2011 there will be more focus on the industrial sector. The utilities reported high participation and energy savings in commercial programs, which ran out of funding in June 2010, especially commercial lighting. Some of the utilities had to decrease their rebates because they were so popular. The current emphasis is on reaching more customers with current programs rather than trying new technologies to get deeper savings, although in the future they are hoping a whole-house approach will replace some of the savings lighting programs are capturing now. Consumers Energy filed an amended Energy Optimization Plan for 2011-2014.

One future direction DTE Energy has begun moving in is an emphasis on customer behavior. They will be piloting a behavior-change program contracting with the OPower company in 2011. OPower has been sweeping across the country. The firm sends customers a two-page letter comparing customer energy use with their neighbors. This gives homeowners a basis of comparison on their energy use. DTE Energy believes that OPower's track record of savings is as much as 2 to 3 % savings relative to a control group. DTE will be ramping up the scale of this program in 2012.

Prognosis

Detroit Edison and MichCon both expect to be— and have MPSC-approved Energy Optimization Plans for—exceeding EEPS savings levels every year through 2015. Energy savings were 140% of the goal in 2009 and are expected to be even higher for 2010. DTE Energy is exceeding their goals in order to get the maximum amount of recovery costs that are allowed. In the future, as there are less savings to acquire, they anticipate that it will get harder and harder to meet savings goals within the cost recovery limit.

Consumers Energy savings levels will be sustained into the future. They anticipate over the long term that they will need to go to the next tier after they get the low hanging fruit.

Ohio

Background

Ohio electric utilities provided extensive energy efficiency programs to their customers during the 1990's, saving a cumulative annual 1,198 GWh by 1996, the fourteenth highest among all states (York & Kushler 2002). In 1999, Ohio restructured their electric markets, beginning with Spending and energy savings declined over the next thirteen years as there was relatively little efficiency program activity. Ohio natural gas utilities also run efficiency programs, but there is no natural gas efficiency portfolio standard. One electric efficiency initiative that continued was the state-administered Energy Efficiency Revolving Loan Fund, part of the ratepayer-funded Advanced Energy Fund, which was instituted in 1999. A universal service rider, a type of surcharge, supports the Ohio Energy Loan Fund, providing low income bill assistance and efficiency incentives. The charge is $0.0001758 per kWh or approximately $15 million per year.

Ohio's largest electric utility is First Energy, with 1.8 million customers in Ohio served by three operating companies: Ohio Edison, Toledo Edison, and the Illuminating Company. Second is American Electric Power of Ohio (AEP OH), with 1.5 million customers served by two operating companies: the Columbus Southern Power Company and the Ohio Power Company. Duke Energy Ohio and Dayton Power & Light Company (DP&L) both have over a half-million customers. These four investor-owned utilities sell almost 90% of all retail electricity in the state.

The distribution utilities administer their own energy efficiency programs with oversight from the Public Utilities Commission of Ohio (PUCO). The PUCO may also modify the utilities' proposed programs. Ohio's investor-owned utilities are required to prepare and implement energy efficiency plans. On April 15 of each year, each electric utility must file its long-term forecast and benchmark report regarding compliance with baselines and benchmarks for energy efficiency and peak reduction programs with the Commission.

Ohio's Energy Efficiency Resource Standard Policy

Senate Bill 221, signed into law May 1, 2008, included both an Energy Efficiency Portfolio Standard (EEPS), and Alternative Energy Portfolio Standard (RPS), among other provisions. For efficiency, it requires a gradual ramp up to a cumulative 22 percent reduction in electricity use by 2025. Beginning in 2009, the Act requires electric distribution utilities to implement energy efficiency programs that achieve energy savings equal to at least three-tenths of one per cent of sales. The annual savings requirements increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one per cent in 2012, nine-tenths of one per cent in 2013, one per cent from 2014 to 2018, and two per cent each year thereafter, achieving a cumulative energy savings in excess of twenty-two per cent by the end of 2025.

Table 28: Ohio Percent Energy Savings Requirements by Year, 2009-2009

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020-25
0.30%	0.50%	0.70%	0.80%	0.90%	1.00%	1.00%	1.00%	1.00%	1.00%	2.00%	2.00%

Sales are defined as the normalized annual average kilowatt-hour sales of the utility for the preceding three calendar years to their Ohio customers.

All surplus energy savings may be banked and used to meet future energy efficiency or advanced energy benchmarks. The utilities are responsible to meet their share of the overall statewide goal, however, they may include savings from their large industrial ("mercantile") customers in their proposed plan filings to PUCO. The issue of mercantile savings approval by the PUCO has received substantial attention, and has engendered some controversy, among environmental stakeholders in particular. One major concern is that the inclusion of energy savings from the past has no additive value and directly displaces new efficiency.

Penalty and Off-Ramp

Failure to comply with energy efficiency savings requirements will result in forfeiture by the utility. The amount is either that prescribed by the legislature or the existing market value of one renewable energy credit per MWh of undercompliance or noncompliance. Any revenue from forfeiture is credited to the Advanced Energy Fund. The commission may amend the benchmarks if, after application by the electric distribution utility, the commission determines that the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control.

Funding and Policy Approaches to Achieve Increased Savings

Ohio's EEPS mandates a level of savings by the third year (0.6%) that other Midwestern states who are among the national leaders in utility efficiency, with populations and electricity use half the size, took twice as long or longer to reach. Rapid acceleration in program budgets is one way Ohio has been priming the pump and making possible the development of the necessary efficiency infrastructure. Ohio's electric utilities increased their collective budgets for energy efficiency programs from approximately $20 million per year between 2006 and 2008 to $152.8 million in 2010, according to the Consortium for Energy Efficiency[64].

Shareholder incentives and decoupling are two policy approaches supporting utility efforts to capture increasing annual savings.

Shareholder Incentives

Financial incentives to utilities for achieving energy savings may be approved by PUCO on a case-by-case basis. First Energy and AEP have had performance incentives approved. Duke Energy was recently approved for incentives as part of the regulatory approval of more than a dozen residential and commercial demand side management programs and related cost recovery. The recovery mechanism is

[64] Consortium for Energy Efficiency, 2010 Annual Industry Report, State and Provincial Tables. http://www.cee1.org/ee-pe/docs/Table%204.pdf

an annually reconciled rider, which includes conditioned adjustments for shared savings with a maximum 10% shareholder incentive if at least 65% of targeted savings are achieved.

Decoupling
In the Public Utilities Commission of Ohio's (PUCO) rules, the commission may provide for decoupling, and an electric distribution utility may submit an application for approval of a revenue decoupling mechanism to the PUCO. Lost revenue recovery mechanisms for electric and gas utilities are determined on a case-by-case basis. All of Ohio's electric utilities recover program costs. Duke recovers lost revenues resulting from their portfolios of energy efficiency programs via the DSM rider. Dayton Power & Light had their electric security plan approved by PUCO, which extends their existing generation rate plan through Dec. 31, 2012. Rule: ORC §4928.143(B)(2)(h); Duke riders: Docket Nos. 06-0091-EL-UNC, 06-0092-EL-UNC, and 06-0093-GA-UNC

DP&L's original plan filing was designed to be rolled out in conjunction with smart grid deployment and it included a ten-year plan for energy efficiency. However, smart grid is not moving ahead in Ohio. PUCO approved DP&L's Electric Security Plan[65], which includes efficiency program plans, on June 24, 2009. It will run through Dec. 31, 2012. One area that DP&L is looking to find savings is utility system voltage upgrades, which will reduce line losses and are accounted for as energy savings according to the EEPS. The savings achieved will be established using engineering calculations. AEP's initial electric security plan also provided for the implementation of their gridSMART program, which was intended to enable customers to control their electric use using advanced metering technology.

Program evaluation is conducted with a high proportion of measures given deemed savings values, which decreases the administrative cost of impact evaluations. Evaluations are performed program-by-program by independent third-party contractors. Utilities file compliance reports to PUCO annually. For purposes of the EEPS, gross savings are used.

Collaboratives/stakeholder engagement are encouraged but not mandated in the PUCO efficiency rules.

Administrative and Program Strategies to Achieve Increased Energy Savings

Three of the four major IOUs began their efficiency initiatives under the EEPS with portfolios of predominantly tried-and-true energy efficiency programs. At DP&L, during the initial phase of the EEPS they are implementing a series of traditional energy efficiency programs, heavily emphasizing lighting. In their initial seven-year (2008-2015) plan proposal, 75% of residential savings were from CFLs. The majority of energy savings for DP&L are in the commercial and industrial sectors, which includes government customers. These business programs offer prescriptive rebates for over 100 measures including motors, HVAC equipment, and air compressors and were introduced in the spring of 2009 when the EEPS went into effect. The project planning cycle is much longer for program managers in the business sector as it takes time and effort to build relationships with contractors. For residential, programs include an upstream CFL buydown, appliance rebates, rebates and tune-ups for electric furnaces, low income programs, and a school-based educational program delivered and facilitated by the Ohio Energy Project called E-3. The E-3 programs does provide energy savings DP&L can get credit for, but the intent is to have a broader impact.

AEP began implementing programs in mid-2009, also filing their Energy Security Plan with traditional programs. The subsidiaries filed efficiency portfolio plans to PUCO as one plan that was the result of a long process in which they hired a contractor to conduct an energy efficiency potential study, started a multi-stakeholder collaborative, investigated best practices, and then put together a suite of new programs. (See testimony in cases 09-1089 in DIS and 09-1090). One major energy-saving effort was a very large CFL markdown program, for 1.8 million light bulbs in 2009 and then 3.8 million

[65] Dayton Power & Light, Energy Efficiency and Demand Response Plan
http://www.dpandl.com/documents/EnergyEfficiencyandDemandResponsePlan.pdf

Duke's portfolio of programs that was approved by PUCO as part of their 2008 three-year filing emphasizes lighting. Since the passage of the federal Energy Policy Act of 2005, Duke Energy Ohio has been speeding up their timeline for gaining savings from CFLs on the residential side and lighting options for commercial and industrial customers as well. The upcoming federal changes will also impact businesses as well, because the increased efficiency standard will reduce the amount of savings per lamp that utility program administrators may claim. As LED lighting is not yet cost effective under Ohio cost-effectiveness tests, in 2012 Duke may use an early replacement CFL program—to get residential customers to install the bulbs they have already bought—in order to be able to count the savings toward their EEPS targets. Another significant technology category in 2010 was HVAC, which had benefited from the combination of Duke rebates and federal tax credits, providing a stronger incentive for customers to install high-efficiency equipment.

Duke is not currently offering additional incentives to customers for installing multiple measures per project. Instead, they are emphasizing broad participation rather than deep savings per customer, in part, at least, to capture as much lighting savings as possible before federal standards take full effect and have there full impact. This is also partially due to the fact that cost effectiveness is determined at the measure level, so less cost-effective end use technologies, even if they add an increment of savings to a project, it may be screened out and not meet the test. To increase more customers, they are learning how to best utilize different communication methods including online channels, integrated voice recognition phone systems, mailers, and business reply cards.

Duke is moving more and more toward a behavioral approach with customers, although the persistence of energy savings achieved is an issue. For example, they are doing a pilot project for home energy comparison reports, which enables homeowners to see whether they are using more energy than their neighbors or less energy.

Early Results, Responses, and Outlook

PUCO had not approved energy efficiency program plans filed by FirstEnergy Corporation until March, 2011. The three other IOUs met their savings targets of 0.3% for 2009 and 0.5% for 2010. To meet the statewide goal in the future, savings from FirstEnergy will be needed. FirstEnergy's plan would have contributed 151,829 MWh for 2010; that figure increases to 432,993 for the year 2012.

Table 29: Energy Efficiency Performance by Utility in 2009 and 2010

Utility	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
American Electric Power[66]	136,944	**171,000**	125%	228,125	**306,000**	134%
Dayton Power & Light[67]	43,193	**40,442**	94%	71,781	**101,061**	141%
Duke Energy[68]	68,127	**86,402**	127%	109,420	**310,755**	284%
FirstEnergy[69]	166,310	**22,614**	14%	N/A	N/A	N/A
Total	**414,574**	**320,458**	**77%**	**409,326**	**717,816**	**175%**

AEP has also exceeded savings targets, in part because of their successful commercial and industrial efforts. Ohio allows C&I customers to opt-out of paying the energy efficiency rider is they are able to demonstrate historical energy savings. Qualifying businesses may apply. AEP offered a plan to their large business customers such that the customer continues to stay in the rider, AEP pays 75% of what they would have saved by opting out, and the customer can use that money for efficiency improvements.

[66] Savings calculated on a pro-rated basis. 2009: Docket No. 10-0318-EL-EEC; 2010: 11-1299-EL-EEC
[67] Savings calculated on a pro-rated basis. Docket No. 10-0303-EL-POR; 2010: 11-1276-EL-POR
[68] Calculated as incremental savings. 2009: Docket No. 10-0317-EL-EEC (Appendix A); 2010: 11-1311-EL-EEC
[69] Requirements for 2009 through 2012 waived. 2009 savings achieved filed in Docket No. 10-0277-EL-EEC

The customer receives a lump sum, pays into the rider, and is eligible to participate in AEP's efficiency programs.

Three Ohio IOUs are getting cost recovery. DP&L is also recovering some lost revenues. The rate rider is up for review by March or April, 2011. AEP began implementing some efficiency programs before they were approved by PUCO, so they were not able to recover their program costs until May 2010. Duke has their Save-A-Watt program instead, so they receive a percent of the avoided cost of the energy-savings impacts of their efficiency program portfolio.

DP&L made only minor changes from the first program year to the second. The administration and management of the CFL program was simplified. New programs included a government facility audit program in which DP&L will pay half the cost of a qualified energy audit, and will pay the full cost if efficiency upgrades are made within one year. Another new program added in 2010 was a new construction rebate, integrated with other utilities, sharing construction vendors.

AEP's new home construction energy efficiency program has benefited by improvement in the home construction market overall. They are partnering with Columbia Gas and share the same contractor and coordinate the gas and electric elements of the program. AEP is also doing more and more market segmentation, such as adding programs targeted to agricultural energy customers and to restaurants.

Market Transformation

The utilities efficiency efforts do play important roles in market transformation. However, the Ohio program administrators we spoke with did not place great importance on market transformation because savings are difficult to measure and utilities do not get credit toward their EERS goals for this work. The Ohio regulatory framework does not provide direct financial incentives for utilities to work on market transformation related activities such as codes and standards enforcement.

Prognosis

The efficiency portfolio and program planning cycle is three years. Utilities are now at the start of the process for 2012-14. The reliance on lighting savings will need to diminish after the federal EISA standards come into effect. ACEEE, together with Summit Blue Consulting has recommended five innovative programs be added to lighting and other proven utility programs in our report, "Shaping Ohio's Energy Future: Energy Efficiency Works." These advanced residential and commercial buildings initiatives, manufacturing, rural and agricultural initiatives, and combined heat and power were recommended in conjunction with five complementary policies primarily under the jurisdiction of the state government. Together, these initiatives would achieve about half of the 22% savings required under the EEPS by 2025.

According to AEP, most of the programs they will have in place over the next three year cycle will look very similar to current programs. AEP will be expanding home energy audit efforts and making the audits more extensive, integrate with existing home retrofits, and expand from the current home retrofit pilot with Columbia Gas, as well as work with a third party to do on-bill financing. For 2012 to 2014, AEP will sit down to develop a collaborative approach with Columbia Gas. Commercial retro-commissioning is an area that AEP will look to for substantial savings. In addition, the company wants to find a way for utilities to get a percentage of the energy savings resulting from building codes and appliance standards. Raising the baseline for efficiency standards erodes the savings a utility may claim relative to the savings their programs have achieved between the new efficient equipment and the "as found" level of efficiency.

In the longer term beyond the next 3 to 5 years, they will be looking at industrial long-range planning, continuous improvement, and integrating energy efficiency with industrial process improvement to get more energy savings.

For Duke Energy Ohio, much of their efficiency program outlook depends on changes to codes and standards, and how utilities may or may not get credit for part of the savings due to them. Attribution influences what types of programs they offer, especially when planning 7 or 8 years into the future. Before then, there will be challenges due to the steep growth curve of annual savings requirements. One lesson learned is to allow time for marketing messages to catch on and for programs to be ramped up. The alternatives to emphasizing CFLs to reap quick MWh savings are capital intensive, yet the utilities may only charge avoided costs. To go beyond the more straightforward efficiency measures requires more staff, but there is a lag time to get them hired and trained while developing programs and getting them into the field.

References

York, D. and M. Kushler. 2002. *State Scorecard on Utility and Public Benefits Energy Efficiency Programs: An Update.* Washington, D.C.: American Council for an Energy-Efficient Economy.

EXHIBIT

State of the Efficiency Program Industry

Budgets, Expenditures, and Impacts 2011

CEE℠

Consortium for Energy Efficiency

For more information, contact:
Patrick Wallace
Research Assistant
Evaluation and Research
pwallace@cee1.org
(617) 337-9279
Consortium for Energy Efficiency
98 North Washington Street, Suite 101
Boston, MA 02114
March 14, 2012

SC\NRDC EXHIBIT 11

Terms of Use

Acknowledgements

CEE would like to thank the gas and electric efficiency program administrators in the United States and Canada that participated in this year's industry data collection. We appreciate the time and effort given by all survey respondents throughout the data collection process, including the extensive clarification and data validation follow-up. The list of participating organizations can be found in Appendices A and B.

CEE would also like to thank the American Gas Association and the Institute for Electric Efficiency, which were once again major contributors to this year's report. We use a common data instrument to eliminate multiple requests for the same information, as well as coordinate and share in data collection.

CEE also acknowledges the reviewers working in the field of energy efficiency who have provided informal feedback and insights on this work over the years. Reviewers include, but are not limited to, CEE members and staff of the American Council for an Energy-Efficient Economy, Natural Resources Canada, and the Energy Information Administration. We welcome additional feedback from readers to help inform future reports.

This report was produced by Patrick Wallace, Research Assistant, and Hilary Forster, Senior Program Manager of the CEE Evaluation and Research team. Elizabeth Carbone provided valuable data collection and management work during the summer of 2011.

Contents

Figures

Executive Summary

This report looks retrospectively at the state of energy efficiency program budgets, expenditures, and savings for natural gas and electric ratepayer-funded programs in the United States and Canada. The report provides 2010 industry data, including program expenditures and energy savings and includes budgets for 2011 at the time of the data collection. The primary purpose of these data is to illustrate the magnitude of the ratepayer-funded energy efficiency program industry and to provide a timely sense of industry trends.

This is the sixth annual industry data collection conducted by CEE, and the third year in a row that CEE partnered with the American Gas Association (AGA) and the Institute for Electric Efficiency (IEE) to collect data on gas and electric efficiency program budgets, expenditures, and impacts from administrators across the United States and Canada. Working with these organizations has streamlined data collection and increased the participant size and response rate for this survey.

Every year CEE and our collaborators aim to increase participation in the survey. This year CEE, together with IEE and AGA, obtained data from 352 utility and nonutility program administrators operating efficiency programs in 47 states and seven Canadian provinces. This response rate is 11 percent higher than last year.

Below are the key findings from this year's industry data collection:

- US and Canadian combined gas and electric efficiency program budgets reached $9.1 billion in 2011. CEE members' programs accounted for 86 percent of this total, or $7.8 billion. US and Canadian gas and electric efficiency program budgets have increased by 21 percent, up from $7.5 billion in 2010.
- US and Canadian efficiency programs saved approximately 124,000 GWh of electricity and over 1.3 billion therms of gas in 2010. This resulted in 92.0 million metric tons of avoided CO_2 emissions from entering the atmosphere.
- Electric budgets in California and New York topped $1 billion each. Together, California, New York, Massachusetts, and Florida accounted for 50 percent (or $3.4 billion) of the total amount budgeted for electric energy efficiency in the United States. Nine states—New York, Massachusetts, Pennsylvania, Maryland, New Jersey, Indiana, Tennessee, Arizona, and California— and the Northwest[1] represented 80 percent of the growth in budgets since last year.
- Natural gas efficiency program budgets in the United States and Canada increased slightly to $1.3 billion, up from a budget of $1.2 billion in 2010.
- Canadian gas and electric efficiency program budgets rose by 22 percent and topped the $1 billion mark for the first time ($1.14 USD, $1.10 billion CAD) in 2011. In 2010, administrators spent over $820 million ($791 million CAD) on efficiency program.

---

[1] The Northwest region is defined as program activities carried out by the Bonneville Power Administration (BPA) and the Northwest Energy Efficiency Alliance (NEEA) in Idaho, Montana, Oregon, and Washington. Other energy efficiency programs in those states are reported separately by state.

- Canadian electric efficiency program budgets in Ontario, Québec, and British Columbia accounted for 89 percent (or $893 million CAD) of the total amount budgeted for electric efficiency in 2011 ($1.00 billion CAD). Ontario alone accounts for over 42 percent of Canada's total 2011 electric efficiency program budgets.

1 Introduction

The State of the Efficiency Program Industry report looks retrospectively at US and Canadian energy efficiency program budgets, expenditures, and savings for natural gas and electric ratepayer-funded programs. This report seeks to provide the most timely[2] and accurate[3] industry data comprised of 2011 budgets and 2010 expenditures and savings. Timely data is important because it illustrates an accurate snapshot of this rapidly changing and dynamic industry, and allows for better analysis. Collecting this information was made possible through the joint efforts of CEE and industry collaborators,[4] and the contribution of CEE members.[5] The data collected in this report are meant to supplement, and not replace, data collected by organizations such as the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC). For the purposes of this report, the term "energy efficiency" includes low income and load management programs, unless otherwise stated.

CEE has administered this survey annually to efficiency program administrators, comprised of investor owned utilities, nonutility program administrators, and a selection of municipal power providers and co-ops, typically with efficiency program budgets of $1 million or more. In 2009, CEE began collaborating with the American Gas Association (AGA)[6] and the Institute for Electric Efficiency (IEE)[7] to provide the most current and comprehensive data available on the efficiency program industry in the United States and to increase participation in the survey.

---

[2] The survey attempts to collect the most recent information. 2011 budget data were collected in the spring and summer of 2011.

[3] CEE does extensive quality control and follow up with respondents to confirm that reported information appropriately answers the survey questions. CEE also works closely with respondents to ensure that energy savings information is reported in a consistent manner wherever possible. For more information about our methodology, please refer to sections two and six of this report.

[4] CEE collaborators in this survey effort include the American Gas Association (AGA) and the Institute for Electric Efficiency (IEE). These relationships are further explained in the next paragraph.

[5] CEE members are comprised of electric and gas efficiency program administrators from across North America. For more information on CEE membership please visit: http://www.cee1.org/cee/membership.php3

[6] The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver safe, reliable, and clean natural gas throughout the United States. There are more than 71 million residential, commercial, and industrial natural gas customers in the U.S., of which 92 percent — more than 65 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. To find out more, please visit: www.aga.org.

[7] The Institute for Electric Efficiency (IEE) is a program of the Edison Foundation, a 501(c)(3) charitable organization. IEE's mission is to advance energy efficiency and demand response among electric utilities. IEE is governed by a Management Committee of electric industry chief executive officers. IEE has a permanent Advisory Committee made up of representatives of the efficiency community, federal and state government agencies, and other informed stakeholders. IEE also has a Strategy Committee

Over the last six years, this report has shown, and continues to show, steady growth in the energy efficiency program industry. Additionally, the increase in the number of survey participants each year indicates that each year's report reflects a more accurate snapshot of the efficiency industry. Of the 352 utility and nonutility program administrators responding to the survey this year, 11 percent of the administrators are either new to efficiency—programs started in 2010—or are reporting for the first time. This represents more than $462 million of the total reported 2011 efficiency program budgets.[8]

The 2011 State of the Efficiency Program Industry is divided into six sections plus appendices. This section, Introduction, provides an overview of the report's scope and reach. Data Collection Overview describes the report's methodology and includes detailed information on how data were collected, survey response rates, and information on how to understand data presented in this report. Efficiency Program Funding in the US and Canada presents national level data and analysis on ratepayer-funded natural gas and electric efficiency programs in the United States and Canada. Products and Services and Evaluation, Measurement & Verification present analysis on the services and products included in efficiency programs and on evaluation, measurement and verification budgets and expenditures, respectively. The final section, Estimated Energy Savings and Environmental Impacts provides estimated national energy savings data from efficiency programs in the United States and Canada. These data are reported by country, fuel type, and customer segment.

Efficiency program budgets and expenditures are available by state and province on the CEE Forum, www.ceeforum.org, or by written request to reports@cee1.org. CEE also publishes program data by organization for many respondents on the CEE Forum. Energy savings data are aggregated and reported at the regional level for the United States and at the national level for Canada. Savings data are not reported for states or organizations because of the risk of misinterpretation about program cost-effectiveness.

This is a voluntary survey that is administered annually to program administrators in the United States and Canada. Because responding organizations may vary by state or province from year to year, caution should be used in comparing data and inferring trends, especially at the state or provincial level. Despite extensive follow-up, not all organizations included in the sample frame respond to the survey each year. Thus, the changes from year to year in the data reported here cannot be entirely attributed to new or expanded programs and new program administrators.

AGA and IEE were major contributors to this year's report. Partnering with these organizations has streamlined data collection and expanded the sample pool of program administrators in the United States and Canada. AGA and IEE publish more information on efficiency programs, including a summary of budgets and expenditures as reported here, energy savings data, program implementation and evaluation, and regulatory information on the efficiency program

---

comprising senior energy industry executives that identify strategies and projects for IEE. To find out more, please visit: www.edisonfoundation.net

[8] This number is underestimated because it does not take into account data from five natural gas utilities, which reported to AGA for the first time in 2010 but did not agree to release their budgets and expenditures data to CEE at the organizational level.

industry. These organizations may be contacted directly for more information on their publications, which are publicly available on their websites. For more information on this report, or to obtain copies of the graphics produced for this report, please contact Sarah Griffith, CEE Strategic Communications Director, at reports@cee1.org or visit cee1.org or, for members, ceeforum.org.

2 Data Collection Overview

2.1 Collaboration

CEE collected data throughout the spring and summer of 2011 in conjunction with AGA and IEE. The survey frame includes previous survey respondents, all member organizations of IEE, AGA, and CEE, and nonmembers who submitted data to EIA on Form 861. Because the energy efficiency industry is in a rapid state of change, it is very difficult to identify and survey every efficiency program. CEE attempted, however, to make its sample frame as comprehensive as possible. Due to the vast number of community-owned electric utilities, the survey, for the most part, focused on the municipal power providers and co-ops that had efficiency program budgets of about $1 million or more.[9]

CEE, with IEE, collected all electric program data. CEE, with AGA, collected gas program data. The survey aimed to collect the most up-to-date information, as well as permission to show program expenditures and budget data at the organizational level, from all respondents. In some cases, where CEE knew that there were electric programs running but did not survey them, we used secondary public data filings to obtain basic information on budgets, expenditures, and impacts.[10] "Respondents" in this report include organizations that provided CEE, IEE, and AGA with data directly or aggregately through state agencies or nonutility program administrators as well as information collected through public filings.

2.2 Response Rate

Every year, through outreach and collaboration, CEE aims to increase participation in the survey. This year, CEE, together with IEE and AGA, obtained data from 352 utility and nonutility program administrators operating efficiency programs in 47 states and seven Canadian provinces. The number of respondents to this year's survey is 11 percent higher than the number that responded last year. The CEE member electric response rate was 97 percent this year, up one percentage point from last year.[11] Finally, only a few known electric efficiency program administrators did not provide data to CEE this year. Therefore, CEE concludes that

---

[9] There are many community-owned electric utilities operating efficiency programs in the US that are not included in this report. The American Public Power Association (APPA), a nonprofit organization created to serve the nation's more than 2,000 community-owned electric utilities that collectively deliver power to more than 46 million Americans, plans to independently collect data on the efficiency program budgets and expenditures of its members in the future. For more information about APPA, go to: www.publicpower.org.

[10] This includes information for 38 community-based electric utilities in California. CEE obtained this data from the California Municipal Utilities Association's March 2011 Status Report *Energy Efficiency in California's Public Power Sector*. This document can be found at: http://www.cityofpaloalto.org/civica/filebank/blobdload.asp?BlobID=13217.

[11] A list of responding organizations appear in Appendices A and B. The number of organizations in these appendices seems low compared to the number of organizations reported above because some organizations may be counted as separate entities in different states for the purposes of calculating response rates.

the vast majority of large electric efficiency program administrators are represented in this report.

AGA collected most of the gas program data for this report. There were a total of 140 utility and nonutility program administrators in the gas sample frame.[12] According to AGA, the gas survey response rate was 95 percent of known gas efficiency programs. CEE members accounted for approximately 63 percent of this response rate. CEE and our collaborators have produced a report that represents the vast majority of the energy efficiency program industry. CEE acknowledges, however, that this report does not capture every energy efficiency program in the United States and Canada. Therefore, the statements made herein may be conservative.

2.3 Data & Participants

2.3.1 Ratepayer Funding

All electric and natural gas efficiency program funding reported here is from ratepayers through public benefits charges or other rate funding mechanisms. Some additional efficiency program funding originates from sources other than ratepayers. These are termed "non-ratepayer funding" for the purposes of this report. This includes but is not limited to funding from the Regional Greenhouse Gas Initiative (RGGI), the New England Forward Capacity Market, state or federal agencies, and the American Recovery and Reinvestment Act (ARRA); these funds are excluded from this report.[13]

2.3.2 Program Information

CEE worked extensively with responding organizations to ensure the data they reported were consistent with the data we requested. When CEE identified what appeared to be outlying values in the data, we contacted those organizations to find the source of unexpected values and worked with them to obtain the correct information.

Changes to program budgets after the summer of 2011, such as those due to newly approved programs or budget cuts, have not been reflected here. Some dollars reported in 2011 represent carryover of unspent funds from 2010.

2.3.3 Reporting Period

CEE asked respondents to provide program expenditures and impacts data for the 2010 calendar year and budgets for the 2011 calendar year by customer class. Not all energy efficiency program administrators' program or fiscal years match the calendar year. In some cases, data may reflect program or fiscal year data rather than calendar year data.

---

[12] Forty-seven (47) organizations in the sample were found to not be running efficiency programs. These organizations were excluded from the response rate calculation.

[13] This non-ratepayer funding, which has been subtracted from program expenditures and budgets in this report, is noted in the organizational level data that are published on the CEE Forum (www.ceeforum.org).

2.3.4 Reporting Categories

The categories "commercial and industrial," "residential," "load management," "low income," and "EM&V" are used in this report because they are both common and straightforward, but not all programs use these exact categories. In particular, the contents of the "other" category vary by state and province. "Other" includes items that not all program administrators allocate by sector such as administration, advertising, agriculture, codes and standards, education and training, general support, planning, research and development, and any program budgets or expenditures that are not allocable by customer class.

Finally, some respondents were not able to separate low income program dollars from residential program funds, and a small number of commercial program dollars were combined with residential program funds. Given that respondents may interpret survey questions differently, expenditure and budget data should be regarded as estimates rather than exact figures.

The low income data understate what states and provinces budget for low income programs because many low income weatherization programs receive significant amounts of federal funding and are run by state or provincial agencies not included in this report. For this reason, the category should be considered as representing only ratepayer-funded low income programs, and the data provided to CEE may differ from other published information about the efforts of particular program administrators.

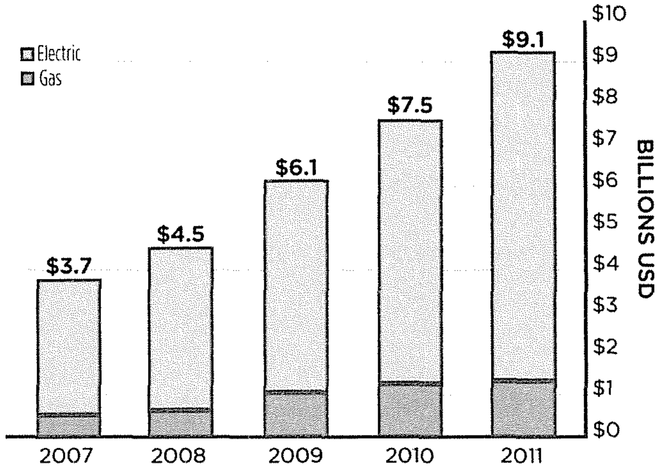
2.3.5 Currency

For ease of reading, all currency is reported in US dollars (USD) unless otherwise specified. This report uses the July 11, 2011 Bloomberg exchange rate of 1.037 USD = 1 CAD throughout. For prior years, the following exchange rates were used: 0.9544 USD = 1 CAD for 2010 budgets and 2009 expenditures, 0.9339 USD = 1 CAD for 2009 budgets and 2008 expenditures, 0.9345 USD = 1 CAD for 2008 budgets and 2007 expenditures, and 1 USD = 1 CAD for 2007 budgets and 2006 expenditures.

3 Efficiency Program Funding in the US and Canada

US and Canadian electric and gas efficiency program budgets reached $9.1 billion in 2011. This is a 21 percent increase from the $7.5 billion budgeted in 2010. As Figure 1 illustrates, budgets for efficiency programs continue to increase rapidly despite a weak economy since 2008.

Figure 1. US and Canadian Efficiency Program Budgets, 2007-2011

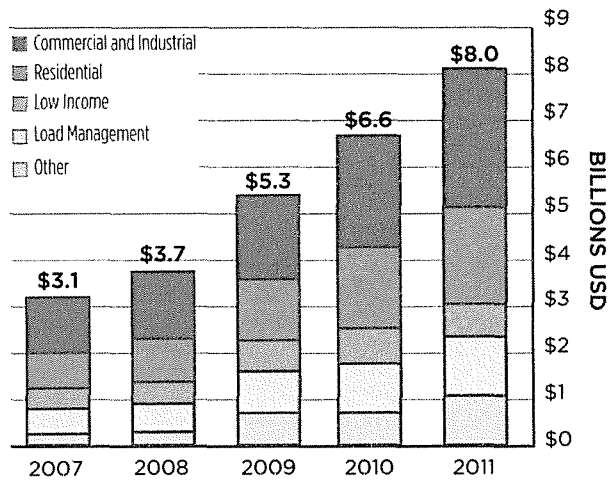


CEE members accounted for $7.8 billion, or 86 percent, of the total US and Canadian gas and electric efficiency program budgets. Across the United States and Canada, reporting program administrators spent $6.5 billion on gas and electric efficiency program expenditures in 2010, an increase over the $5.3 billion they collectively spent in 2009.

3.1 United States

In 2011, US administrators budgeted over $8 billion for gas and electric energy efficiency, more than two and half times the reported program budgets in 2007 (Figure 2). In 2010, reporting natural gas and electric efficiency program administrators in the United States spent $5.7 billion on energy efficiency. This is an increase of more than $1 billion from what US administrators spent on gas and electric efficiency programs in 2009 ($4.6 billion).

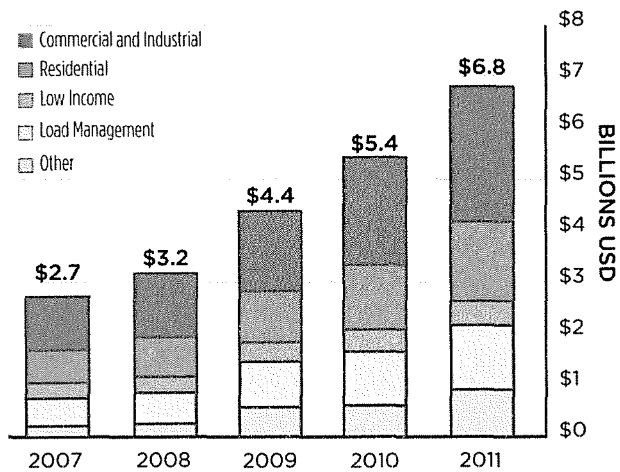
Figure 2. US Combined Electric and Gas Program Budgets, 2007–2011



3.1.1 Electric Efficiency Programs

US administrators budgeted more than $6.8 billion for their electric programs in 2011. This is an increase of approximately 26 percent over reported 2010 program budgets (Figure 3). For those administrators who responded to CEE data requests in both 2010 and 2011, electric efficiency budgets increased by 24 percent this year.

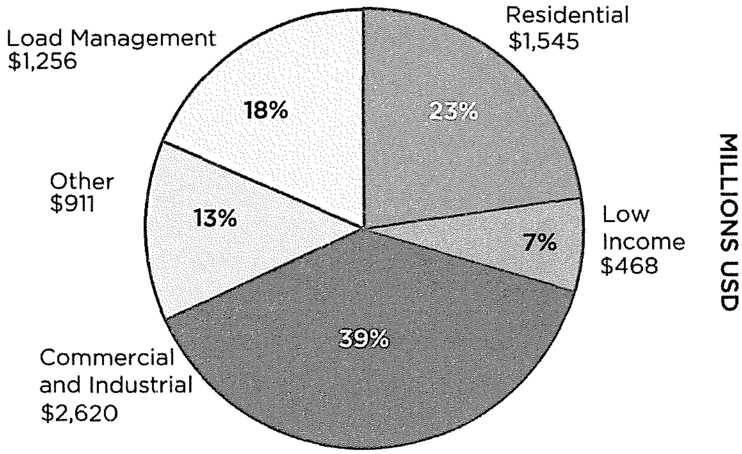
Figure 3. US Electric Program Budgets, 2007–2011



Electric program administrators spent $4.8 billion on energy efficiency in 2010, which is an increase of approximately $1 billion over the $3.8 billion spent on US electric efficiency programs in 2009.

Data continue to show that commercial and industrial efficiency programs receive the largest share of electric program funding, followed by residential efficiency, load management, and low income programs. Administrators allocated an average of 13 percent of their total program budgets to "other", which includes programs not otherwise allocable by customer class such as administration, market research, planning and development, pilot programs, marketing and outreach, and education. (Figure 4).

Figure 4. US Electric Program Budgets by Customer Class, 2011



The 2011 budget percentage breakdown by customer class shown above is nearly identical to the 2010 budget breakdown reported last year despite a large increase in budgets overall.[14]

Separating Commercial and Industrial Dollars For the first time, this year CEE surveyed participants to gather information to better separate commercial and industrial program expenditures and budgets. CEE collected this information to better understand how program administrators are able to separate their commercial and industrial program dollars and to provide the energy efficiency program industry with more detail about these market segments.

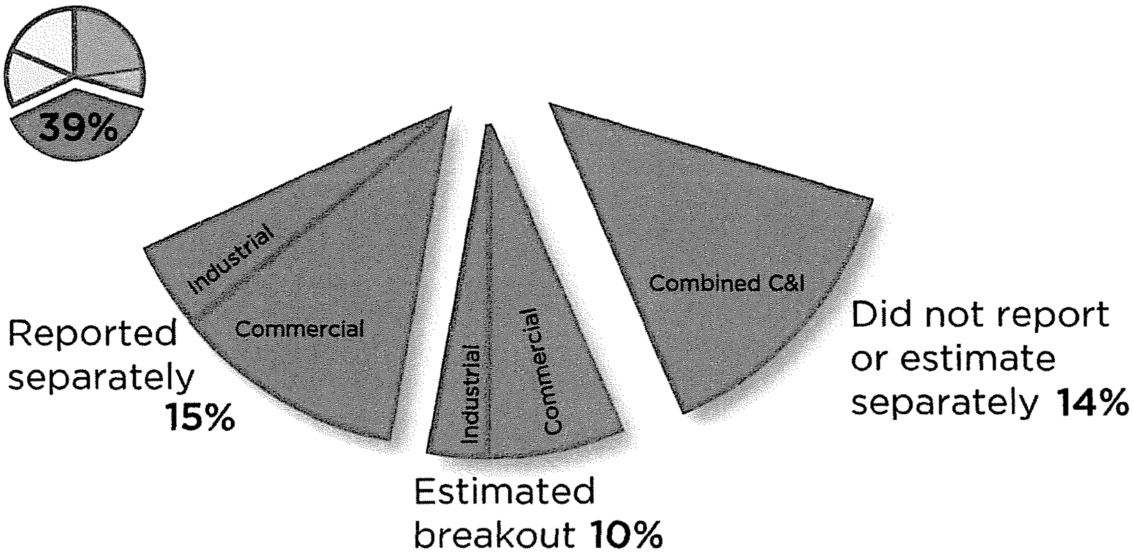
CEE asked respondents to report expenditures and budgets on commercial and industrial programs separately. If respondents were unable to provide a separate figure for each sector, CEE asked them to estimate the percentage of their combined commercial and industrial budgets that were allocated to industrial programs.

Figure 4 shows that US electric commercial and industrial program budgets accounted for 39 percent of the total amount budgeted for US electric programs. Figure 5 breaks this out further and indicates that respondents representing 15 percent of the total amount budgeted for US electric programs reported commercial and industrial budgets separately, 10 percent provided a percentage estimate of the amount of money budgeted for their separate commercial and industrial programs, and 14 percent provided a budget for their combined commercial and industrial programs only.

---

[14] Consortium for Energy Efficiency. *State of the Efficiency Program Industry: 2009 Expenditures, Impacts and 2010 Budgets.* http://www.cee1.org/ee-pe/2010AIR.php3, posted December 2010. © Copyright 2010 Consortium for Energy Efficiency. All rights reserved.

Figure 5. Breakout of US Electric Commercial and Industrial Program Budgets by Reporting Category



There is some variance in the certainty of these data due to differing interpretations among respondents of what constitutes a commercial or an industrial program, and because the accuracy of participants' percentage breakout estimates haven't been verified. Therefore this information should not be used to make inferences about commercial or industrial budgets alone. CEE plans to continue expanding and refining this effort in future reports to better understand the size of the commercial and industrial sectors respectively.

Expenditures vs. Budgets This year CEE sought to understand the dollars spent on electric programs in 2010 in relation to the 2010 budget estimates from the previous year.

Figure 6. 2010 US Electric Budgets vs. 2010 US Electric Expenditures (Millions USD)

2010 Budgets Last Year's Report	2010 Expenditures This Year's Report	Percent Difference	Absolute Difference
5,174	4,626	11.8%	548

Note: This table includes only those organizations that responded to the survey in both 2010 and 2011. Values above are approximate.

US electric program administrators collectively budgeted nearly $550 million dollars more for energy efficiency programs than they spent in 2010 (Figure 6). There are many potential reasons for why budgets and expenditures differ, and CEE plans to explore collecting more detailed information regarding these differences in future reports.

Electric Efficiency Budgets by State Electric budgets in California and New York topped $1 billion each in 2011. Together, California, New York, Massachusetts, and Florida accounted for $3.4 billion, or nearly 50 percent, of the total amount budgeted for electric energy efficiency programs in the US.

As noted above in Figure 3, US electric program budgets have grown by approximately $1.4 billion since 2010. Nine states—New York, Massachusetts, Pennsylvania, Maryland, New

Jersey, Indiana, Tennessee, Arizona, and California—and the Northwest[15] represented 80 percent of the growth in budgets since last year (Figure 7).

Figure 7. Growth in US Electric Efficiency Program Budgets (Millions USD)

States	Absolute Annual Growth	2010 Budgets	2011 Budgets	Percent Annual Growth
New York*	495	601	1,096	82%
Northwest**	134	107	241	125%
Pennsylvania	120	151	270	79%
Massachusetts	120	281	401	43%
Maryland	97	114	210	84%
New Jersey	84	228	313	37%
Indiana	57	24	81	238%
Tennessee	53	64	117	83%
Arizona	44	96	140	46%
California	43	1,494	1,537	3%

Notes: *A program administrator in this state included budget dollars this year for line items that it had not included in the past. **The Northwest is defined as program activity by the Bonneville Power Administration (BPA) and the Northwest Energy Efficiency Alliance (NEEA) in Idaho, Montana, Oregon, and Washington. Other energy efficiency programs in those states are reported separately by state.

The efficiency programs in the ten states that have spurred the most growth in the US electric efficiency program market span all regions of the country—the Northeast, Midwest, South, Southwest, and Pacific Coast.

States that showed strong growth as a percentage of their budgets include Arkansas, Virginia, South Dakota, and Mississippi (Figure 8). Two states and the District of Columbia reported budgets in 2011 that did not report budgets in 2010.

Figure 8. Growth in Electric Efficiency Program Budgets by Percentage (Millions USD)

States	Percent Annual Growth	2010 Budgets	2011 Budgets	Absolute Annual Growth
West Virginia	No Budget in 2010	0	7	7
District of Columbia	No Budget in 2010	0	1	1
North Dakota	No Budget in 2010	0	1	1
Arkansas	767%	3	26	23
Virginia	396%	Less than 1	1	1
Indiana	238%	24	81	57
South Dakota	219%	Less than 1	1	Less than 1
Northwest**	125%	107	241	134
Maryland	84%	114	210	96
Mississippi	83%	18	33	15

[15] The Northwest region is defined as program activities by the Bonneville Power Administration (BPA) and the Northwest Energy Efficiency Alliance (NEEA) in Idaho, Montana, Oregon, and Washington. Other energy efficiency programs in those states are reported separately by state in this report. The Northwest region is defined differently in the Institute for Electric Efficiency's *Summary of Ratepayer-Funded Electric Efficiency Impacts, Budgets, and Expenditures (2010–2011)* report.

States	Percent Annual Growth	2010 Budgets	2011 Budgets	Absolute Annual Growth
New York*	82%	601	1,096	495

Notes: *A program administrator in this state included budget dollars this year for line items that it had not included in the past. **The Northwest is defined as program activity by the Bonneville Power Administration (BPA) and the Northwest Energy Efficiency Alliance (NEEA) in Idaho, Montana, Oregon, and Washington. Other energy efficiency programs in those states are reported separately by state.

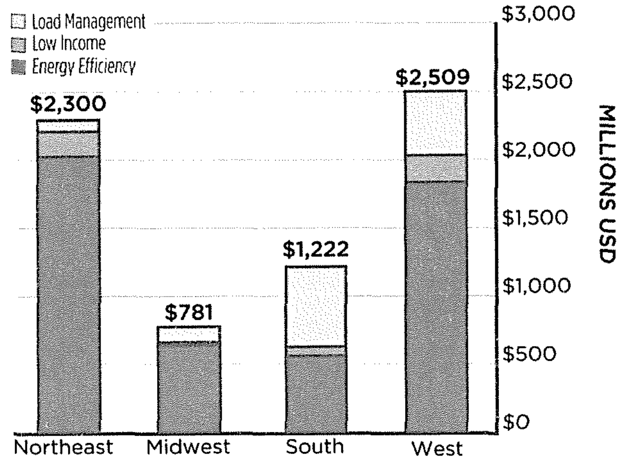
New York, Maryland, Indiana and the Northwest region were both among the top ten in terms of absolute annual growth and percentage annual growth over last year's budgets.

3.1.2 Load Management

Once again, this year CEE collected data on load management budgets and expenditures for electric efficiency program administrators. CEE defines load management programs as those programs that contain direct load control, interruptible demand, or price response interventions.[16]

US electric load management budgets totaled $1.3 billion in 2011. The southern United States continues to invest heavily in load management with over 48 percent of the region's total 2011 efficiency program budgets going to this category. The west continues to invest in load management as well, $470 million, in 2011.

Figure 9. US Electric Efficiency Program Budgets by Region, 2011



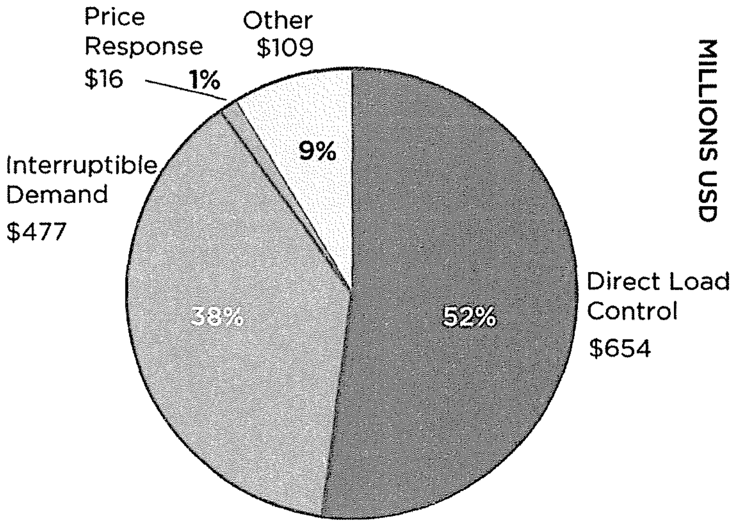
While load management represented nearly half of the South's electric program budgets, load management comprised only about 19 percent of the West's 2011 electric program budgets.

In the US, over half, 52 percent, of load management program budgets were invested in direct load control (Figure 10). This was followed by interruptible demand at 38 percent and price response at one percent. "Other" load management programs comprised nine percent of the

[16] These terms come from the US Energy Information Administration's glossary of terms. To view the glossary, please visit: http://205.254.135.7/tools/glossary/

total load management program budgets in 2011 and included programs not otherwise allocable by program type.

Figure 10. US Electric Load Management Program Budgets, 2011

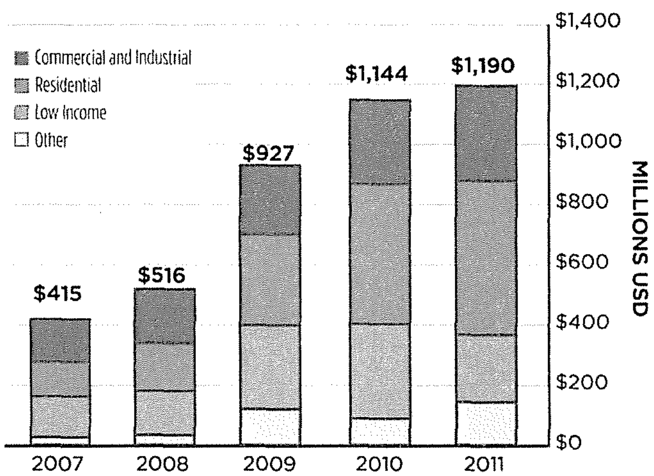


Again, these percentages are similar to the percentages observed last year despite a substantial increase in the amount of money budgeted to load management programs.

3.1.3 Natural Gas Efficiency Programs

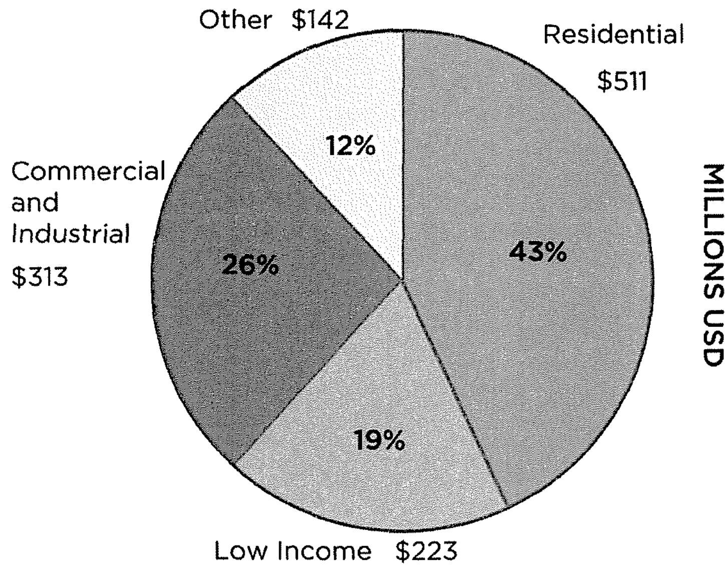
Natural gas efficiency program budgets in the United States continued to increase in 2011 (Figure 11). This year, reporting administrators budgeted nearly $1.2 billion for gas efficiency programs. In 2010, US administrators spent about $838 million on gas efficiency programs, up from approximately $803 million in 2009.

Figure 11. US Gas Program Budgets, 2007–2011



Residential energy efficiency programs comprised the largest percentage of 2011 gas program budgets at 43 percent, followed by commercial and industrial programs at 26 percent, and low income programs at 19 percent (Figure 12). "Other" programs comprised 12 percent of the total efficiency program budgets and included programs that were not otherwise allocable by customer class. The percentages observed below are similar to those observed in last year's report despite an increase in budgets overall.

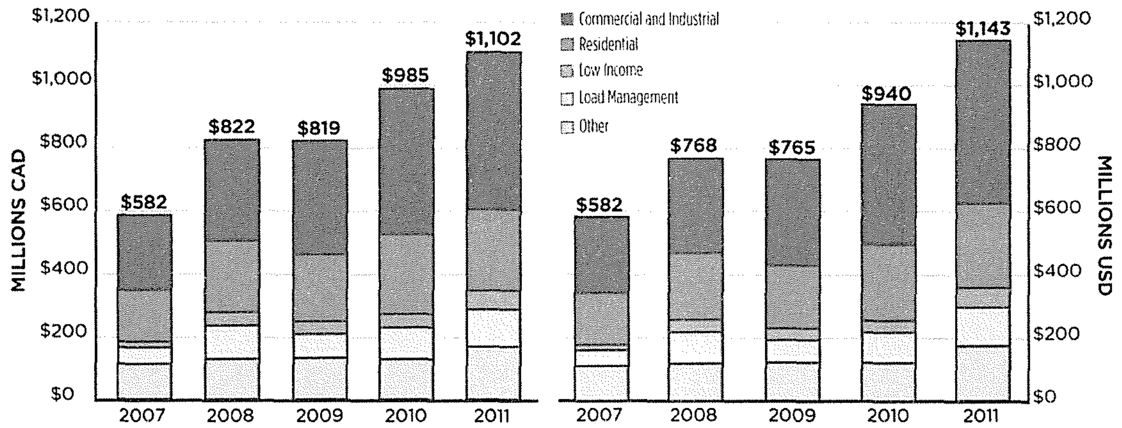
Figure 12. US Gas Program Budgets by Customer Class, 2011



3.2 Canada

In 2011, Canadian electric and gas budgets topped a billion dollars for the first time at $1.14 billion ($1.10 billion CAD). This is a 22 percent increase[17] from reported 2010 program budgets and is over 95 percent more than reported 2007 program budgets (Figure 13). In 2010, reporting natural gas and electric efficiency program administrators in Canada spent $821 million ($791 million CAD) on energy efficiency, an increase of more than $100 million over the $682 million ($714 million CAD) that was spent by these administrators collectively in 2009.

Figure 13. Canadian Electric and Gas Program Budgets, 2007-2011

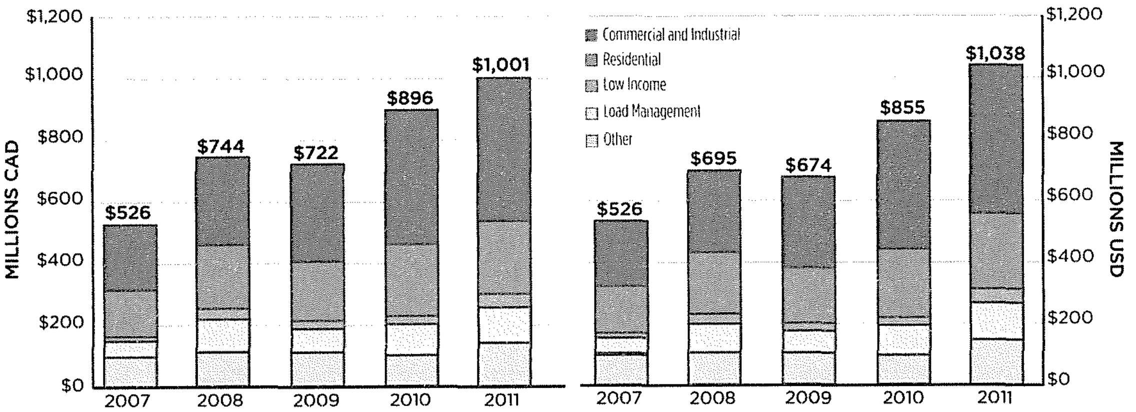


[17] Growth rates are calculated using US dollars.

3.2.1 Electric Efficiency Programs

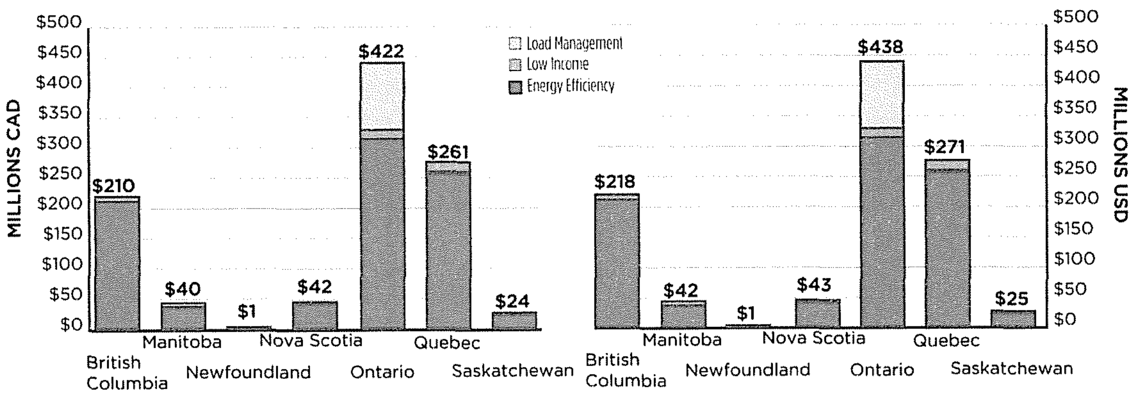
Electric efficiency comprises over 90 percent of the total reported Canadian efficiency program budgets for 2011. Canadian electric program budgets topped $1 billion dollars for the first time coming in at $1.04 billion ($1.00 billion CAD), which is a 21 percent increase in program budgets from 2010 (Figure 14). In 2010, Canadian electric administrators spent $745 million ($718 million CAD), up from the $615 million ($644 million CAD) they spent on these programs in 2009.

Figure 14. Canadian Electric Program Budgets, 2007-2011



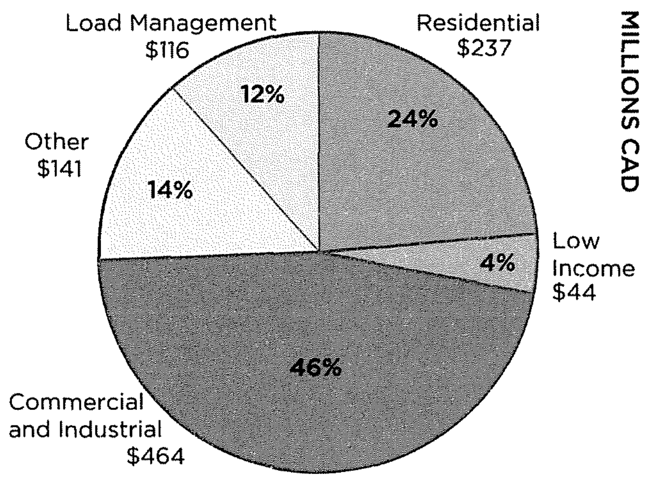
Ontario, Québec, and British Columbia represent nearly 90 percent of the total amount budgeted for electric efficiency programs in 2011 (Figure 15). Ontario alone accounts for more than 40 percent of the nation's total 2011 electric efficiency program budgets.

Figure 15. Canadian Electric Program Budgets by Province, 2011



Commercial and industrial programs received the largest share, 46 percent, of 2011 electric program budgets in Canada (Figure 16). This is followed by residential programs at 24 percent, load management programs at 12 percent, and low income programs at four percent. "Other" programs, which are not otherwise allocable by customer class, comprised 14 percent of total 2011 electric efficiency program budgets.

Figure 16. Canadian Electric Program Budgets by Customer Class, 2011

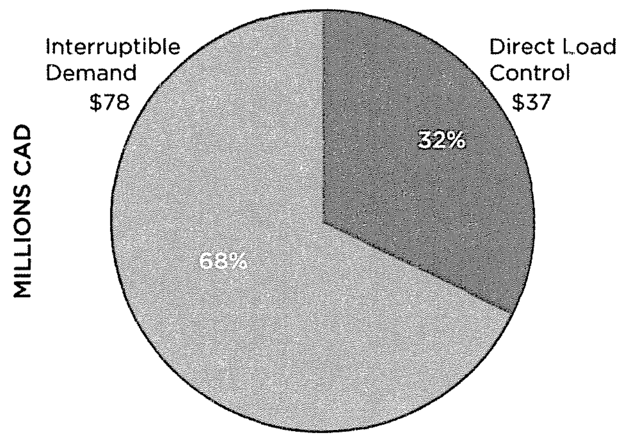


The percentages observed in Figure 16 are similar to those observed in previous years despite an increase in budgets.

3.2.2 Load Management

Canadian electric program administrators budgeted nearly $120 million ($116 million CAD) in 2011 for load management. Sixty-eight (68) percent of Canada's load management budgets in 2011 were invested in interruptible demand, and the remaining 32 percent were invested in direct load control (Figure 17). Ontario reported budgeting for both direct load control and interruptible demand programs, while Quebec and Saskatchewan reported budgeting only for direct load control programs, and Manitoba reported budgeting for only interruptible demand programs. The remaining provinces that reported electric efficiency budgets to CEE (British Columbia, Nova Scotia, and Newfoundland and Labrador) didn't report 2011 load management program budgets.

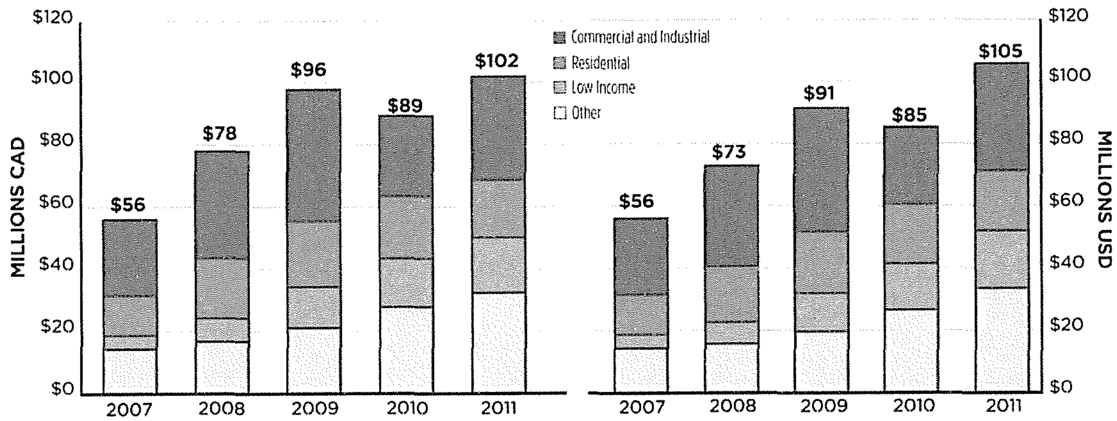
Figure 17. Canadian Electric Load Management Budgets by Customer Class, 2011



3.2.3 Natural Gas Efficiency Programs

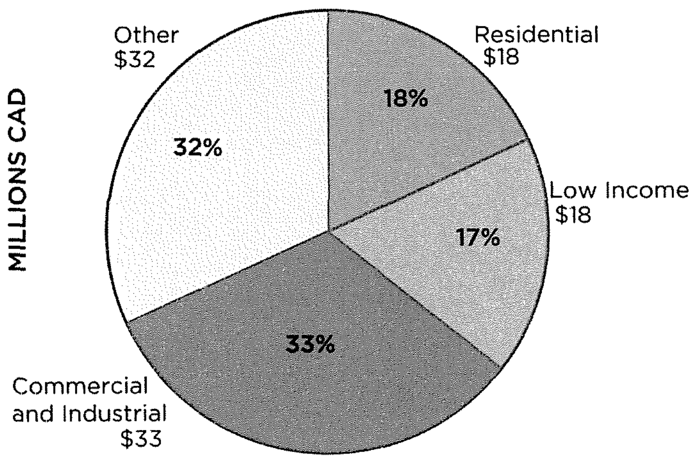
Natural gas program budgets resumed their growth and topped $100 million for the first time in 2011, after showing a slight decline last year from previous years. Since 2007, Canadian gas budgets have grown 88 percent (Figure 18). In 2010, reporting Canadian program administrators spent $76 million ($73 million CAD) on natural gas efficiency programs, up from $67 million ($70 million CAD) in 2009.

Figure 18. Canadian Gas Program Budgets, 2007-2011



Commercial and industrial programs accounted for 33 percent of total Canadian natural gas efficiency program budgets, followed by residential programs (18 percent) and low income programs (17 percent). "Other" programs accounted for 32 percent of the total efficiency program budgets and include programs that are not otherwise allocable by customer class (Figure 19).

Figure 19. Canadian Gas Program Budgets by Customer Class, 2011



4 Products and Services

For the third year in a row, CEE asked respondents to identify the product categories included in their programs from a range of products common to efficiency programs. The results are shown for the United States and Canada, and are listed in descending order by the percentage of respondents that indicated that the product or service was included in their programs.

Figure 20. Products and Services Included in Electric Efficiency Programs, US and Canada

Electric Programs	Percent	Electric Programs	Percent
Residential		**Commercial**	
Compact Fluorescent Lights	85%	Lamps	87%
Heat Pumps	78%	Ballasts	85%
Air Conditioners	68%	Packaged Units	79%
New Construction (whole home)	63%	Controls	77%
Appliance Recycling	56%	Unitary	73%
Refrigerators	52%	Solid State Lighting	72%
Whole House Retrofit	50%	Unitary Heat Pump	72%
Fluorescent Fixtures	49%	New Construction (whole building)	63%
Quality Installation	42%	Energy Management	60%
Room Air Conditioners	40%	Retrofit (whole building)	60%
Tune-up/Controls Upgrade	39%	Data Centers/IT	50%
Clothes Washers	38%	Kitchens	49%
Behavior	38%	Tune-up/Controls Upgrade	48%
Windows	33%	Heat Pumps Water Heaters	41%
Heat Pump Water Heater	29%	Quality Installation	22%
Lighting Controls	28%		
LED Replacement Lamps	28%	**Industrial**	
LED Fixtures	27%	Drives	77%
Dishwashers	25%	Motors	72%
Solar Thermal Water Heater	22%	Custom	66%
Advanced Power Strips	19%	Prescriptive	54%
Televisions	18%	Plant Assessments	50%
Pool Pumps	15%	Continuous Energy Improvement/	
Computers	15%	Strategic Energy Management	35%
Computer Monitors	14%	Separate Agriculture Program	23%
Set-top Boxes	7%		
		Financing	
Multifamily		On-bill Loan	13%
Retrofit	55%	Other Financing	13%
New Construction	42%	On-bill Tariff	4%

Figure 21. Products and Services Included in Gas Efficiency Programs, US and Canada

Gas Programs	Percent	Gas Programs	Percent
Residential		**Industrial**	
Furnaces	90%	Custom	40%
Storage Water Heater	75%	Prescriptive	33%
Boilers	73%	Plant Assessments	31%
Tankless Water Heater	58%	Continuous Energy Improvement/Strategic Energy Management	24%
Whole House Retrofit	50%		
New Construction (whole home)	44%		
Tune-up/Controls Upgrade	39%		
Quality Installation	31%		
Direct Heating Equipment	21%		
Clothes Washers	20%		
Windows (any product)	20%		
Solar Thermal Water Heater	12%		
Dishwashers	10%		
Commercial			
Boilers	64%		
Furnaces	62%		
Storage Water Heaters	57%		
Tankless Water Heaters	51%		
Kitchens (any product)	45%		
Tune-up/Controls Upgrade	44%		
Unit Heaters	39%		
New Construction (whole building)	37%		
Energy Management	36%		
Retrofit (whole building)	36%		
Gas-fired Packaged Unitary Equipment	31%		
Solar Thermal Water Heaters	19%		
Quality Installation	18%		

5 Evaluation, Measurement & Verification

CEE, with IEE and AGA, asked respondents to report spending on Evaluation, Measurement and Verification (EM&V) in 2010 and the amount budgeted for EM&V in 2011. Please note that the table below (Figure 22) includes only those programs that reported a dollar figure for their EM&V expenditures and budgets.[18]

Based on 2011 electric energy efficiency budgets, 79 percent of US and Canadian electric efficiency administrators provided a separate dollar figure for their EM&V activities in 2011.[19,20]

Not all respondents budget or conduct evaluation on an annual basis, and other respondents didn't fill out this portion of the survey. Furthermore, because evaluation and its related program budgets do not necessarily occur in the same time frame, caution is urged when comparing program budgets to dollars for EM&V activities.

Figure 22. Electric and Gas EM&V Expenditure and Budget Dollars, US and Canada (Millions USD): For the portion of respondents who reported an EM&V dollar figure*

Electric

Country	2010 EM&V Expenditures	2011 EM&V Budgets	Total 2011 Energy Efficiency Budgets**
United States	58	154	4,239
Canada	11	32	895
Total	69	186	5,134

Gas

Country	2010 EM&V Expenditures	2011 EM&V Budgets	Total 2011 Energy Efficiency Budgets**
United States	9	27	782
Canada	1	Less than 1	78
Total	10	27	860

Notes: *The above table includes only those programs that provided an EM&V dollar figure. Those who provided an estimated percentage of their EM&V activities from their total energy efficiency funding are not included. **Dollar figures in the Total 2011 Energy Efficiency Budgets column exclude load management because CEE did not ask for EM&V expenditures and budgets in the load management portion of the survey.

[18] CEE asked respondents who were unable to report their EM&V activities as a separate line item to provide an estimate of their EM&V activities as a percentage of their total energy efficiency expenditures and budgets. This information is not included in this report however, because it could not be combined in an accurate way.

[19] This figure cannot be determined for gas respondents because not every organization that reported their information to AGA agreed to release their data to CEE at the organizational level.

[20] These budgets exclude load management because CEE did not ask for EM&V expenditures and budgets in the load management portion of the survey.

6 Estimated Energy Savings and Environmental Impacts

CEE collected data on energy efficiency impacts from gas and electric program administrators in 2010.[21] In order to help respondents report their impacts consistently across states and provinces, CEE used the Energy Information Administration's (EIA) definitions of annual and incremental effects.[22]

CEE sought to collect net annual effects from all respondents, but many organizations were unable to report their impacts in this manner.[23] If a respondent was unable to provide net annual effects, we used gross annual effects. If annual effects were not provided, then CEE used net or gross incremental effects, as available.

Although CEE worked with respondents to ensure that impacts data were reported as consistently as possible, many organizations calculate and report impacts according to reporting requirements in their states or provinces, which may or may not be consistent with EIA definitions. Not all organizations were able to adjust their estimates to reflect EIA definitions or across jurisdictions. Also, because of the timing of the request and differing evaluation cycles across organizations and jurisdictions, impacts were often reported prior to evaluation and are subject to change.

6.1 Electric Efficiency Program Savings

Ratepayer-funded energy efficiency programs are saving energy and reducing the amount of greenhouse gases emitted in the United States and Canada. Reporting efficiency programs in the United States and Canada estimated savings of approximately 124,000 GWh of electricity in

---

[21] CEE also collects data on energy savings from load management programs, however, these data are not reported by region or nation because it cannot be aggregated in a meaningful way.

[22] According to the EIA Form EIA-861, incremental effects or impacts include "all energy savings that accumulated from new participants in existing programs and all participants in new programs in 2010." Annual effects or impacts are defined as "all energy savings that accumulated from participation in existing or previously implemented programs (including those terminated since 1992) during the calendar year 2010 and the ramped impacts from new programs, or new participants in existing programs, during the calendar year 2010." We asked respondents to consider the useful life of efficiency measures by accounting for building demolition, equipment degradation, and program attrition when calculating annual effects.

[23] Net effects exclude whatever is typically excluded in the jurisdictions of reporting organizations. This often includes, but is not limited to, free riders, savings due to government mandated codes and standards, and the "natural operations of the marketplace," such as reduced use because of higher prices and fluctuations in weather or business cycles.

2010 (Figure 23).[24] This is equivalent to 85.5 million metric tons of avoided CO_2 emissions.[25] CEE members' programs accounted for 89 percent of these estimated savings.

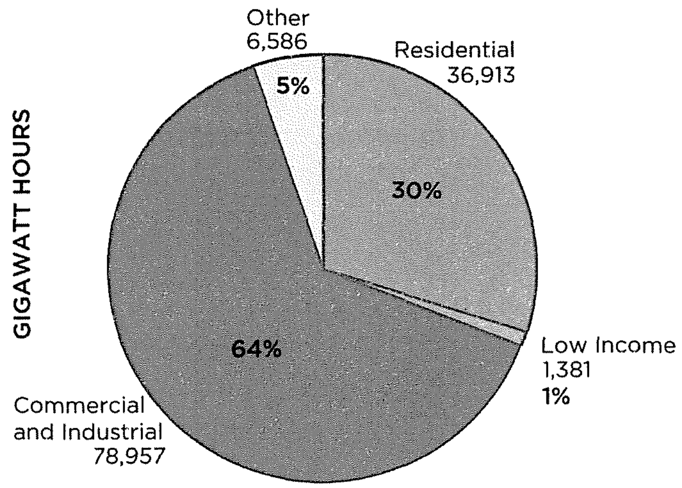
Figure 23. Estimated Annual Electric Energy Savings for 2010 (GWh)*

	Residential	Low Income	C & I	Other	Total
United States**					
Northeast	8,358	439	28,328	734	37,859
Midwest	4,519	77	12,319	305	17,220
South	7,625	174	6,404	17	14,220
West	12,915	616	25,801	3,837	43,170
Subtotal, United States	33,417	1,306	72,852	4,893	112,468
Canada***	3,496	75	6,105	1,693	11,368
Binational Electric Total	36,913	1,381	78,957	6,586	123,837

Notes: *Based on estimated 2010 savings from measures installed in 2010, as well as from measures installed as early as 1992 that were still generating savings as of 2010 (i.e. "annual effects"). **Seventy-one (71) percent of respondents reported annual effects. For respondents that did not report annual effects, CEE used incremental effects in calculating totals. ***Eighty-eight (88) percent of respondents reported annual effects. For respondents that did not report annual effects, CEE used incremental effects in calculating totals.

Across the United States and Canada, commercial and industrial electric programs accounted for almost two-thirds of the total energy savings (64 percent), followed by residential (30 percent) and low income programs (one percent). "Other" accounted for five percent of the total energy savings and includes programs not otherwise allocable by customer class (Figure 24).

Figure 24. Electric Efficiency Program Savings by Customer Class, 2010



[24] This figure represents a combination of annual and incremental impacts. About 60 percent of respondents that reported savings data provided net impacts. The remainder provided gross impacts.

[25] Calculated using the EPA Greenhouse Gas Equivalencies Calculator. Accessed December 2011, http://www.epa.gov/cleanenergy/energy-resources/calculator.html.

In 2010, the value of electric efficiency savings across the United States and Canada was $12.0 billion ($11.6 billion CAD).[26]

6.2 Natural Gas Efficiency Program Savings

Reporting natural gas efficiency programs in the United States and Canada estimated savings of over 1.3 billion therms of gas in 2010 (Figure 25).[27] This is equivalent to 6.5 million metric tons of avoided CO_2 emissions. CEE members' programs accounted for 82 percent of the total energy savings estimate.

Figure 25. Estimated Annual Gas Energy Savings for 2010 (MDth)*

	Residential	Low Income	C & I	Other	Total
United States					
Northeast	14,356	2,131	11,841	428	28,757
Midwest	8,729	1,472	8,505	1,702	20,408
South	385	45	141	0	571
West	8,454	1,181	19,525	1,924	31,084
Subtotal, United States	31,924	4,829	40,013	4,054	80,820
Canada	11,249	12,262	30,146	127	53,784
Binational Gas Total	43,173	17,091	70,159	4,181	134,604

Notes: * Based on estimated 2010 savings from measures installed in 2010, as well as from measures installed as early as 1992 that were still generating savings as of 2010 (i.e. "annual effects").

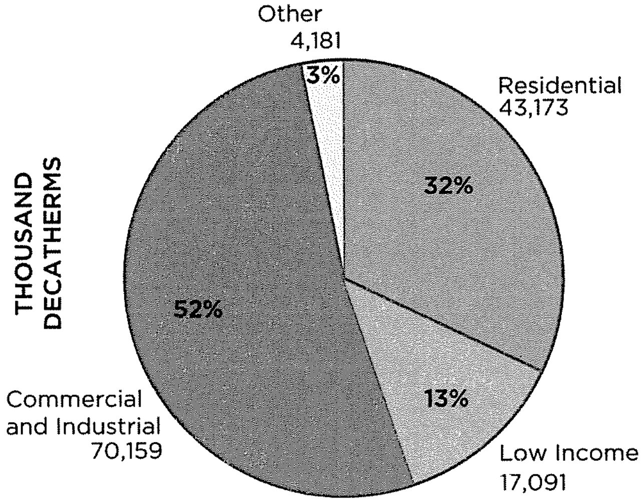
Across the United States and Canada, commercial and industrial programs accounted for the majority of energy savings (52 percent), followed by residential programs (32 percent) and low income (13 percent). "Other" accounted for three percent of the estimated natural gas energy savings and includes programs not otherwise allocable by customer class (Figure 26). As a percentage, commercial and industrial savings were lower, and low income savings were higher than the savings observed in last year's report.

---

[26] US electric retail values were calculated based on the average rate per kWh across the US in 2010 using data from the Energy Information Administration's Annual Report on Electric Sales, Revenue, and Price. Accessed December 2011. Average electric rates used: $0.1154 per kWh (residential) and $ 0.0848 per kWh (commercial/industrial). Canadian electric retail values were calculated based on the average rate per kWh across Canada in 2010 using data from National Energy Board of Canada. Average electric rate used: $ 0.107 CAD per kWh (all sectors).

[27] According to AGA, about 47 percent of respondents that provided savings data reported net impacts, with the remainder providing gross savings. This figure represents a combination of annual and incremental effects.

Figure 26. Gas Efficiency Program Savings by Customer Class, 2010



In 2010, the value of natural gas energy efficiency savings across the United States and Canada was $1.30 billion ($1.26 billion CAD).[28]

[28] US gas retail values were calculated based on the average rate per therm across the US in 2010 using data from Energy Information Administration: Natural Gas Annual Report, Table 24: Average Price of Natural Gas Delivered to Consumers by State. Accessed December 2011. Average gas prices used: $1.0905 per therm (residential) and $0.7082 per therm (commercial and industrial). Canadian gas retail values were calculated based on the average rate per therm across Canada in 2010 using data from National Energy Board of Canada. Average natural gas rate used: $1.03 CAD per therm (all sectors).

Appendix A List of Electric Survey Respondents

Alabama Power Company
Alameda Municipal Power
Alliant Energy
Ameren Corporation
American Electric Power
Anaheim Public Utilities
Arizona Public Service Company
Austin Energy
Avista Corporation
Azusa Light & Water
Baltimore Gas & Electric Company
Black Hills Energy
Bonneville Power Administration
British Columbia Hydro and Power Authority
Burbank Water & Power
Burlington Electric Department
Cape Light Compact
CenterPoint Energy Houston Electric, LLC
City of Banning Electric Utility
City of Biggs
City of Healdsburg
City of Hercules Municipal Utility
City of Industry
City of Lompoc
City of Needles
City of Palo Alto Utilities
City of Shasta Lake
City of Vernon Light & Power
City Utilities of Springfield, MO
Clallam County Public Utility District
Colton Electric Utility
Commonwealth Edison Company
Connecticut Light & Power Company
Consolidated Edison Company of New York, Inc.
Consumers Energy
Corona Department of Water and Power
Dayton Power & Light, Inc
Delmarva Power and Light
DTE Energy Company
Duke Energy Corporation
Duquesne Light Company
Efficiency Maine
Efficiency Nova Scotia Corporation (ENSC)
Efficiency Smart
Efficiency Vermont
El Paso Electric Company
Energy Trust of Oregon
Entergy Corporation
Eugene Water & Electric Board
Fitchburg Gas and Electric Light Company
Florida Power & Light Company
Florida Public Utilities
Focus on Energy
Fort Collins Utilities
FortisBC Inc.
Gainesville Regional Utilities
Glendale Water and Power
Great River Energy
Green Cove Springs Electric Utility
Gridley Municipal Utility
Hawaii Energy Efficiency Program
Hydro-Québec
Idaho Power
Imperial Irrigation District
Indianapolis Power & Light Company
Island Energy
Kansas City Power & Light Company
Lassen Municipal Utility District
Lee County Electric Cooperative, Incorporated
LG&E and KU
Lodi Electric Utility
Long Island Power Authority
Los Angeles Dept of Water & Power
Manitoba Hydro
Merced Irrigation District
MidAmerican Energy Holdings Company
Minnesota Power
Modesto Irrigation District
Moreno Valley Utility
National Grid
Nebraska Public Power District
New Hampshire Electric Cooperative, Inc.
New Jersey Board of Public Utilities (NJBPU)
New York Power Authority
New York State Energy Research and Development Authority (NYSERDA)
Newfoundland and Labrador Hydro
Northern Indiana Public Service Company (NIPSCO)
Northwest Rural Public Power District
NorthWestern Energy
NSTAR
NV Energy, Inc.
OGE Energy Corporation
Omaha Public Power District
Oncor Electric Delivery Company LLC
Ontario Power Authority
Orange and Rockland Utilities, Inc.
Otter Tail Power Company
Pacific Gas & Electric Company
Pacific Power
Pasadena Water and Power

PECO Energy Company
Pike County Light & Power Company
Platte River Power Authority
Plumas-Sierra Rural Electric Cooperative
PNM
Port of Oakland
Potomac Electric Power Company
PPL Electric Utilities
Progress Energy
Public Interest Energy Research Program (PIER)
Public Service Company of New Hampshire
Public Service Electric & Gas
Puget Sound Energy
Rancho Cucamonga Municipal Utility
Redding Electric Utility
Riverside Public Utilities
Rochester Public Utilities
Rockland Electric Company
Rocky Mountain Power
Roseville Electric
Sacramento Municipal Utility District
Salt River Project
San Diego Gas & Electric Company
SaskPower
Seattle City Light
Silicon Valley Power
Snohomish County Public Utility District
Southern California Edison
Southern Company
Southern Maryland Electric Cooperative, Inc.
Southern Minnesota Municipal Power Agency
Southwestern Public Service Company
Tacoma Power
Tampa Electric Company
Tennessee Valley Authority
Texas-New Mexico Power Company
The Empire District Electric Company
The Northwest Energy Efficiency Alliance
The United Illuminating Company
Trinity Public Utility District
Truckee Donner Public Utility District
Tucson Electric Power
Turlock Irrigation District
Ukiah Public Utility
Unitil Energy Systems, Inc.
UNS Electric, Inc
Vectren Energy Delivery
Victorville Municipal Utility Services
Wakefield Municipal Gas and Light Department
We Energies
Westar Energy, Inc.
Western Massachusetts Electric Company
Wisconsin Power and Light Company
Xcel Energy Inc.

Appendix B List of Gas Survey Respondents

Ameren Illinois Utilities (Ameren Corporation)
Arkansas Oklahoma Gas Corporation
ATCO Gas
Atmos Energy
Avista Utilities (Avista Corp.)
Baltimore Gas and Electric Corporation (Constellation Energy)
Berkshire Gas Company, The (UIL Holdings Corp)
Black Hills Energy Corporation (formerly Aquila, Black Hills Corporation)
Cascade Natural Gas Corp (MDU Resources Group)
CenterPoint Energy
Central Hudson Gas & Electric Corporation
Chattanooga Gas Company (AGL Resources Inc.)
Citizens Energy Group
City of Palo Alto Utilities
City Utilities of Springfield, MO
Colorado Natural Gas, Inc. (Summit Energy)
Columbia Gas (NiSource Inc.)
Connecticut Natural Gas Corp (UIL Holdings Corp)
Consolidated Edison of New York (Consolidated Edison, Inc.)
Consumers Energy (CMS Energy Corporation)
Delta Natural Gas Company, Inc.
Dominion East Ohio (Dominion Resources, Inc.)
Duke Energy Corporation
Elizabethtown Gas (AGL Resources Inc.)
Empire District Gas Company, The
Enbridge Gas Distribution Inc.
Enbridge St. Lawrence Gas
Energy Trust of Oregon
Equitable Gas Company LLC (EQT Corp.)
Fitchburg Gas and Electric Light Company D/B/A Unitil Massachusetts
Florida City Gas (AGL Resources Inc.)
Florida Public Utilities
Focus on Energy
FortisBC Inc.
Great Plains Natural Gas Co (MDU Resources Group)
Intermountain Gas Company (MDU Resources Group)
Interstate Power and Light Company (An Alliant Energy Company)
LaClede Gas Company (The LaClede Group Inc.)
Manitoba Hydro
Michigan Gas Utilities Corporation (Integrys Energy Group)
MidAmerican Energy Company
Minnesota Energy Resources Corporation (Integrys Energy Group)
Missouri Gas Energy (Southern Union Company)
Montana-Dakota Utilities Company (MDU Resources Group)
National Fuel Gas Distribution Corporation (National Fuel Gas Company)
National Grid
New Jersey Board of Public Utilities (NJBPU)
New Jersey Natural Gas Company (New Jersey Resources)
New Mexico Gas Company (Continental Energy Systems LLC)
New York State Energy Research and Development Authority (NYSERDA)
Nicor Gas (Nicor Inc.)
Northern Indiana Public Service Company (NiSource Inc.)
Northern Utilities, D/B/A Unitil
NSTAR
NV Energy, Inc. (formerly Sierra Pacific Resources)
NW Natural
Orange & Rockland Utilities, Inc. (Consolidated Edison Inc.)
Pacific Gas and Electric Company (PG&E Corporation)
PECO Energy (Exelon Corporation)
Peoples Gas/North Shore Gas (Integrys Energy Group, Inc.)
Peoples Natural Gas (formerly Dominion Peoples)
Philadelphia Gas Works
Piedmont Natural Gas Company, Inc.
Public Interest Energy Research Program (PIER)
Public Service Electric and Gas Company (PSEG)
Puget Sound Energy (Puget Energy)
Questar Gas Company
San Diego Gas & Electric Company (SEMPRA Energy)
SaskEnergy
Source Gas Distribution (SourceGas LLC)
South Jersey Gas (South Jersey Industries Inc.)
Southern California Gas Company (SEMPRA Energy)
Southern Connecticut Natural Gas (UIL Holdings Corp)
Southwest Gas Corporation
TECO Peoples Gas (TECO Energy, Inc.)
Texas Gas Service (ONEOK, Inc.)
The Michigan Consolidated Gas Company (DTE Energy Corp)
UGI Utilities, Inc. (UGI Corporation)
Union Gas Limited (Spectra Energy)
UniSource Energy Services Gas

Vectren Energy Delivery (Vectren Corporation)
Vermont Gas Systems, Inc. (Northern New England Energy Corporation)
Virginia Natural Gas (AGL Resources Inc.)
Washington Gas Light Company (WGL Holdings, Inc.)
We Energies (Wisconsin Energy Group)
Westfield Gas & Electric Department
Wisconsin Power and Light, An Alliant Energy Company
Wisconsin Public Service (Integrys Energy Group)
Xcel Energy Inc.
Yankee Gas Service (Northeast Utilities)

EXHIBIT

CEE

About CEE

Members

Consortium for Energy Efficiency

Home / Contact

About CEE
- How CEE Works
- Fact Sheet
- Members
- Membership
- Board
- Meetings
- Initiative Development
- Calendar
- Directions
- Contact
- Site Map

EE Program Industry

Residential

Commercial

Industrial

Gas Programs

Multifamily

Government

Evaluation

Resource Library

Consumer information

New England

Berkshire Gas
Cape Light Compact
Columbia Gas of Massachusetts
Connecticut Light and Power
Connecticut Natural Gas
Efficiency Maine
Efficiency Vermont
Fraunhofer Center for Sustainable Energy Systems
Massachusetts Department of Energy Resources
National Grid
New England Gas Company
New Hampshire Electric Cooperative
Northeast Energy Efficiency Partnerships
NSTAR Electric & Gas
Public Service of New Hampshire
Southern Connecticut Gas
United Illuminating
Unitil
Vermont Department of Public Service
Vermont Gas Systems, Inc.
Western Massachusetts Electric Company
Yankee Gas

Middle Atlantic

Con Edison
Long Island Power Authority
New Jersey Natural Gas
New York Power Authority
New York State Energy Research and Development Authority
PECO Energy Company
PPL Electric Utilities
Public Service Electric & Gas
South Jersey Gas
Sustainable Energy Utility

Midwest

AEP Ohio
Alliant Energy - Iowa
Alliant Energy - Wisconsin
Ameren Illinois Utilities
Ameren Missouri

SC\NRDC EXHIBIT 12

Black Hills Energy - Iowa
CenterPoint Energy - Minnesota
Citizens Energy Group
City Utilities of Springfield - Missouri
Columbia Gas of Ohio
Commonwealth Edison
Consumers Energy
DTE Energy
Great Plains Gas
Great River Energy
Indianapolis Power and Light
Iowa Energy Center
MidAmerican Energy
Midwest Energy Efficiency Alliance
Minnesota Department of Commerce
Nebraska Public Power District
Northern Indiana Public Service Company
Omaha Public Power District
Southern Minnesota Municipal Power Agency
Vectren Corporation
We Energies
Wisconsin Focus on Energy
Xcel Energy - Minnesota

South Atlantic

Baltimore Gas & Electric
DC Sustainable Energy Utility
Delmarva Power
Duke Energy
Georgia Power
Gulf Power
Peoples Gas
Pepco
Piedmont Natural Gas
Progress Energy Carolinas, Inc.
Progress Energy Florida, Inc
Tampa Electric Company

South Central

Alabama Power
Arkansas Western Gas
Atmos Energy
Austin Energy
Consumers Energy
Delta Natural Gas
LG&E and KU Energy LLC
Mississippi Power
Oncor Corporation
Tennessee Valley Authority

Pacific Northwest

AVISTA Utilities

Bonneville Power Administration
Cascade Natural Gas
Energy Trust of Oregon
Eugene Water & Electric Board
Idaho Power
Montana-Dakota Utilities
Northwest Energy Efficiency Alliance
Puget Sound Energy
Seattle City Light
Snohomish Public Utility District
Tacoma Public Utilities

Pacific West

California Energy Commission
California Institute for Energy & Environment
City of Palo Alto Utilities
Hawaii Energy Efficiency Program
Los Angeles Department of Water & Power
Northern California Power Agency
Pacific Gas and Electric Company
Sacramento Municipal Utility District
San Diego Gas & Electric
Southern California Edison
Southern California Gas Company

Southwest

Arizona Public Service
Black Hills Energy - Colorado
New Mexico Gas Company
NV Energy
Platte River Power Authority
PNM
Questar Gas
Rocky Mountain Power - Utah
Rocky Mountain Power - Wyoming
Salt River Project
SourceGas - Colorado
Southwest Energy Efficiency Project
Southwest Gas
Tucson Electric Power Company
Unisource Energy Services
Xcel Energy - Colorado
Xcel Energy - New Mexico

Canada

BC Hydro
Efficiency NB
Efficiency Nova Scotia
FortisBC
Gaz Métro
Hydro-Québec
Natural Resources Canada

Newfoundland and Labrador Hydro
Newfoundland Power
Ontario Power Authority
SaskPower
Union Gas

National

Alliance to Save Energy
American Council for an Energy-Efficient Economy
Lawrence Berkeley National Laboratory
National Renewable Energy Laboratory
Natural Resources Defense Council
New Buildings Institute
Oak Ridge National Laboratory
Pacific Northwest National Laboratory

Back to top

http://www.cee1.org
98 North Washington St., Suite 101, Boston MA 02114-1918
617-589-3949 fax 617-589-3948

SC/NRDC EXHIBIT 13

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

and

In the Confidential File Materials at PSC

SC/NRDC EXHIBIT 14

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

and

In the Confidential File Materials at PSC

SC/NRDC EXHIBIT 15

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

and

In the Confidential File Materials at PSC

SC/NRDC EXHIBIT 16

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

and

In the Confidential File Materials at PSC

SC/NRDC EXHIBIT 17

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

and

In the Confidential File Materials at PSC

SC/NRDC EXHIBIT 18

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

and

In the Confidential File Materials at PSC

EXHIBIT

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 19

Witness: David S. Sinclair

Q-19. Refer to the 2011 Resource Assessment at pages 19-22.

a. Explain what economy market purchases mean in the context of the analysis.

b. Provide the source of base case scenario natural gas and electricity prices and explain how these prices are different from those provided by CERA.

c. Explain why off system sales were not allowed in the analysis.

d. Provide a detailed explanation and the results of the analysis that demonstrate why LS Power's simple cycle combustion turbine ("SCCT") options go forward into the final phase analysis and LS Power's CCCT are a higher cost than the CCCT self-build option. Include in the discussion the specific factors that pushed the analysis results toward the self-build option.

e. In Table 16, of the four least-cost options, the 640 MW option is lower cost than either the 690 MW option or the 605 MW option. Explain the differences between these options, i.e., if the production cost savings associated with the 690 MW option do not outweigh its additional capital and gas transportation costs as compared to the 640 MW option, explain why the same does not hold true for the 640 MW option versus the 605 MW option.

f. Table 16 lists Purchased Power Agreements ("PPAs") starting in 2015, but sales beginning in 2012. Explain to what extent beginning the PPAs in 2012 makes a difference in the cost analysis.

A-19.

a. '*Economy market purchases*' refers to the purchase of power in the hourly power market. In the analysis, economy purchases are limited by modeled transmission constraints (please see response to Question No. 23(c)).

SC\NRDC EXHIBIT 19

b. The base case scenario natural gas prices are from PIRA as of February 2011. Electricity prices are developed by the Companies using a software product called AURORAxmp, a proprietary wholesale market analysis software produced by EPIS Inc. The AURORAmap software uses the base scenario natural gas price as an input.

CONFIDENTIAL INFORMATION REDACTED

[redacted]

c. The level of off-system sales is highly dependent on future market electricity prices. Consistent with past evaluations of new sources, the Companies are not proposing any projects that are justified by speculating on future market electricity prices. The analysis in the 2011 Resource Assessment considered each option's impact on the Companies' ability to serve native load only.

d. Please see the response to Question No. 18. The Bluegrass SCCTs were considered in the final Phase II analysis because of the value they add in combination with other options. The Bluegrass SCCTs are less than one-third of the cost of a self-build SCCT, but the Bluegrass CCCT options are more than two-thirds of the cost of the comparable self-build CCCT options. Clearly, if the Bluegrass SCCTs are converted to a CCCT, the option to pair the SCCTs with another alternative is lost. For these reasons, the self-build CCCT options (in combination with the Bluegrass SCCTs) are more valuable than the Bluegrass CCCT options in combination with other alternatives.

e. In three of the four alternatives, the Companies' self-build CCCT options are paired with the purchase of the Bluegrass CTs in 2012. In the other alternative, the 640 MW CCCT is paired with the PPA for the Bluegrass CTs starting in 2015. In addition to capital cost, the differences between these alternatives are driven by the different capacities of the self-build options and the associated impacts on production costs and expansion plans. All other things equal, more CCCT capacity reduces the need for SCCT energy and reduces overall production costs; less CCCT capacity ultimately results in the need for additional capacity sooner. The capital cost of the 605 MW option is $2.2 million lower than the 640 MW option. However, due to its smaller size, the 605 MW option creates the need for additional capacity in 2019, one year sooner than the 640 MW option. The relatively small difference in capital cost between the 605 MW and 640 MW option is more than offset by the costs associated with needing additional capacity sooner.

Arguably, the capacity difference between the 605 and 640 MW self-build options (35 MW) should result in relatively small differences between each option's expansion plan. Therefore, in the updated final Phase II analysis with 2011 Wood Mac/PIRA commodity prices and the new load forecast (see Section 7.2 of the 2011 Resource Assessment at page 29), the Companies assumed that the timing of the first additional unit in the expansion plan for each option is the same. With this change, the relatively small difference in capital cost between the 605 MW and 640 MW option is still more than offset by the costs associated with needing additional capacity sooner (albeit later in the analysis period).

f. For a given alternative, beginning the PPA in 2012 (versus 2015) increases the revenue requirements of the alternative. The costs of the PPA in 2012-2014 more than offset the production cost savings associated with the additional capacity during this period.