



**SIERRA
CLUB**
FOUNDED 1892

December 18, 2013

Via Personal Delivery

RECEIVED

Mr. Jeff Derouen, Executive Director DEC 19 2013
Case No. 2013-00259
Kentucky Public Service Commission PUBLIC SERVICE
211 Sower Blvd. COMMISSION
Frankfort, KY 40601

Re: Case No. 2013-00259 Sonia McElroy and Sierra Club's Responses to East Kentucky Power Cooperative, Inc.'s Information Requests to Sonia McElroy and Sierra Club (Public Version)

Dear Mr. Derouen,

Enclosed, please find one (1) original and ten (10) copies of the public version of Sonia McElroy and Sierra Club's Responses to East Kentucky Power Cooperative, Inc.'s Information Requests, filed today in the above-referenced matter via personal delivery. The specific confidential information contains certain items of information for which the petitioner, Big Rivers Electric Corp., has sought confidential protection in separate petitions dated June 28, 2013, July 12, 2013, September 3, 2013, September 30, 2013, October 22, 2013, and November 12, 2013. One (1) original of the confidential version of this document will be filed with the commission today by Joe Childers, local counsel, via personal delivery. By copy of this letter, all parties listed on the Certificate of Service have been served via USPS and e-mail. Please place this document of file.

Sincerely,

Kristin A. Henry
Senior Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105
Phone: (415) 977-5716
kristin.henry@sierraclub.org

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

DEC 19 2013

PUBLIC SERVICE
COMMISSION

In the Matter of:)

AN APPLICATION OF EAST KENTUCKY)
POWER COOPERATIVE, INC. FOR A)
CERTIFICATE OF PUBLIC CONVENIENCE)
AND NECESSITY FOR ALTERATION OF)
CERTAIN EQUIPMENT AT THE COOPER)
STATION AND APPROVAL OF A COMPLIANCE)
PLAN AMENDMENT FOR ENVIRONMENTAL)
SURCHARGE COST RECOVERY)

CASE NO. 2013-00259

SONIA MCELROY AND SIERRA CLUB'S RESPONSES TO
EAST KENTUCKY POWER COOPERATIVE, INC.'S INFORMATION
REQUESTS TO SONIA MCELROY AND SIERRA CLUB
(CONFIDENTIAL VERSION)

Intervenors Sonia McElroy and Sierra Club (collectively "Environmental Intervenors")
hereby submit their responses and objections to East Kentucky Power Cooperative, Inc.'s
("EKPC") Information Requests.

GENERAL OBJECTIONS

- A. Environmental Intervenors object to Requests to the extent that they seek information that is not relevant to the above-referenced proceedings, Kentucky Rule of Evidence 401.
- B. Environmental Intervenors object to Requests that are not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1).
- C. Environmental Intervenors object to Requests to the extent that they seek information that is protected because it is a trade secret and/or confidential and proprietary commercial and financial information.
- D. Environmental Intervenors object to Requests to the extent that they seek information that

is protected by the First Amendment.

- E. Environmental Intervenors object to Requests that are overly broad, unduly burdensome, oppressive, and calculated to take Sierra Club and its staff away from normal work activities, and require them to expend significant resources to provide complete and accurate answers to EKPC's Request, which are only of marginal value to EKPC, Kentucky Civil Rule 26.02.
- F. Environmental Intervenors reserve all of their evidentiary objections or other objections to the introduction or use of any response at any hearing in this action.
- G. Environmental Intervenors do not, by any response to any Request, waive any objections to that Request.
- H. Environmental Intervenors do not admit to the validity of any legal or factual contention asserted or assumed in the text of any Request.
- I. Environmental Intervenors reserve the right to assert additional objections as appropriate, and to amend or supplement these objections and responses as appropriate.
- J. The foregoing general objections shall apply to each of the following Requests whether or not restated in the response to any particular response.

**KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 1**

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 1: Please indicate how long Ms. McElroy has been a member of Shelby Energy Cooperative, Inc. (“Shelby Energy”).

Response No. 1:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not “reasonably calculated to lead to the discovery of admissible evidence,” Kentucky Civil Rule 26.02(1). Subject to and without waiving the foregoing objections, Sierra Club states that Sonia McElroy and her husband Jay E. Akers have been members of Shelby Energy since 2000.

**KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 2**

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 2: Please provide the following information concerning Ms. McElroy's residence on Lee Port Road in Milton, Kentucky:

- a. What is the total square footage of the residence?
- b. Is the residence heated using electricity?
- c. What was the average monthly electric usage, in kWh, from September 1, 2011 through August 31, 2013 for the residence?

Response No. 2:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1).

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 3

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 3: Please indicate whether Ms. McElroy has undertaken any of the following energy efficiency activities in her residence prior to September 2013:

- a. Replaced incandescent light bulbs with compact fluorescent light ("CFL") bulbs.
- b. If yes, please indicate the total number of light bulbs in use in the residence and how many of that total has been changed to CFL bulbs?
 - a. Unplugged electronics that are not in use.
 - b. Utilized smart power strips.
 - c. Purchased Energy Star appliances and equipment. If yes, please provide a listing of the Energy Star appliances and equipment purchased.
 - d. Applied weather-stripping and caulking to the residence.
 - e. Had an energy audit performed for the residence.

Response No. 3:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1).

**KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 4**

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 4: Please indicate if Ms. McElroy has availed herself of the following demand-side management and energy efficiency programs offered by Shelby Energy:

- a. Net Metering Program.
- b. Button-Up Weatherization Program.
- c. Heat Pump Retrofit Program.
- d. Direct Load Control Program.
- e. EnviroWatts Program.

Response No. 4:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not “reasonably calculated to lead to the discovery of admissible evidence,” Kentucky Civil Rule 26.02(1).

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 5: Please provide the following information concerning the Cumberland Chapter:

- a. The name and mailing address of the Chairman, President, or chief officer of the Cumberland Chapter.
- b. Of the approximately 5,000 members of the Cumberland Chapter, indicate how many of this total are members of the 16 Distribution Cooperatives of EKPC. Provide this count by each Distribution Cooperative and in total.
- c. If the information requested in part b is not available, please explain in detail why the Cumberland Chapter does not have information concerning the electricity providers of its members.
- d. Using the Cumberland Chapter member counts provided in part b above, indicate how many of the following demand-side management and energy efficiency programs each of these members have participated in. Provide these counts by Distribution Cooperative and in total.
 - 1) EnviroWatts Program.
 - 2) Net Metering Program.
 - 3) Touchstone Energy Home Program.
 - 4) Direct Load Control Program.
 - 5) Button-Up Weatherization Program.
 - 6) Heat Pump Retrofit Program.
 - 7) HVAC Duct Sealing Program.
 - 8) Touchstone Energy Manufactured Home Program.
- e. If the information requested in part d is not available, please explain in detail why the Cumberland Chapter does not have information concerning its members participation in the demand-side management and energy efficiency programs offered by the members' electricity providers.

Response No. 5:

- a. Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1). Subject to and without waiving the foregoing objections, Sierra Club states that the Cumberland Chapter is governed by an Executive Committee consisting of 13 members a representative from each of six groups and seven members elected from the general membership. The Executive Committee appoints a Chapter Chair. The current chapter chair is Alice Howell, who resides at 918 Aurora Avenue, Lexington, Kentucky, 40502-1408.
- b. – d. Sierra Club objects to these requests as they seek information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1). Sierra Club objects to these request as they are overly broad, unduly burdensome, oppressive, and calculated to take Sierra Club and its staff away from normal work activities, and require them to expend significant resources to provide complete and accurate answers to EKPC's request for information, which are only of marginal value to EKPC, Kentucky Civil Rule 26.02.

**KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 6**

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 6: Please provide copies of the board resolution or other documentation approved by the Cumberland Chapter authorizing intervention in this proceeding. If there was no board resolution or other documentation authorizing the intervention, please explain how it was decided that the Sierra Club and the Cumberland Chapter would intervene in this proceeding.

Response No. 6:

Pursuant to the Bylaws and Standing Rules of the Sierra Club and Litigation Committee Approval Procedures, the Environmental Law Program of Sierra Club approved intervention in this proceeding. A copy of the Bylaws can be found at: <http://www.sierraclub.org/policy/downloads/bylaws.pdf>. Sierra Club states that it has had no documentation within its possession or control that are not subject to attorney-client privilege or work product protection.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 7

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 7: Please provide copies of the monthly newsletter "The Cumberland" for the months of August 2012 through December 2013. Identify every article, advertisement, or notice that:

- b. Provides links to Kentucky electric utility websites that discuss and promote the various demand-side management and energy efficiency programs offered by the utility. If these links are not included in the newsletter, please explain in detail why this information is not routinely included as part of the newsletter.
- c. Provides information to the reader encouraging contact with their electricity provider to find out what demand-side management or energy efficiency programs are available. If this information is not included in the newsletter, please explain in detail why this information is not routinely included as part of the newsletter.
- d. Provides information concerning financial or other resources available to the reader to encourage the deployment of demand-side management or energy efficiency measures. If this information is not included in the newsletter, please explain in detail why this information is not routinely included as part of the newsletter.

Response No. 7:

Sierra Club objects to these requests as they seek information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1). Sierra Club objects to these request as they are overly broad, unduly burdensome, oppressive, and calculated to take Sierra Club and its staff away from normal work activities, and require them to expend significant resources to provide complete and accurate answers to EKPC's request for information, which are only of marginal value to EKPC, Kentucky Civil Rule 26.02. Subject to and without waiving the foregoing objections, Sierra Club states that the Cumberland Chapter website offers the current monthly newsletter, as well as back issues through the year 2000. These newsletters can be found at:
<http://kentucky.sierraclub.org/theCumberland/archive.asp#.Uq4OrfSrx7o>.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 8

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 8: As of November 27, 2013 the Sierra Club's website, <http://www.sierraclub.org>, lists under "Goals" the following priority campaigns: "Beyond Coal," "Beyond Oil," "Beyond Natural Gas," and "Our Wild America." Several layers within the "Beyond Coal" campaign is a webpage labeled "Efficiency" which suggests four things residential customers could do: use CFL bulbs, unplug electronics when not in use, weatherize the home, and have an energy audit. Does the Cumberland Chapter believe the information presented on the "Efficiency" webpage found on the Sierra Club's website under the "Beyond Coal" priority campaign constitutes an aggressive promotion of demand-side management and energy efficiency programs to residential customers? Please explain the response.

Response No. 8:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope of this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1). Subject to and without waiving the foregoing objections, Sierra Club states that EKPC can refer to the Direct Testimony of Jeff Loiter regarding the levels of demand-side management and energy efficiency that EKPC should employ.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 9

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 9: Also under the “Goals” section of the website is listed 13 other programs covering a variety of topics including electric vehicles, environmental law, genetic engineering, global population, and nuclear free campaign. However, the promotion of demand-side management and energy efficiency programs are not included on that list. To the extent the Cumberland Chapter is aware, please explain in detail why the promotion of demand-side management and energy efficiency programs is not listed as a major program emphasis of the national Sierra Club.

Response No. 9:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope of this proceeding and is not “reasonably calculated to lead to the discovery of admissible evidence,” Kentucky Civil Rule 26.02(1). Sierra Club objects to these request as they are overly broad, unduly burdensome, oppressive, and calculated to take Sierra Club and its staff away from normal work activities, and require them to expend significant resources to provide complete and accurate answers to EKPC’s request for information, which are only of marginal value to EKPC, Kentucky Civil Rule 26.02. Subject to and without waiving the foregoing objections, Sierra Club states the website speaks for itself and that demand-side management and energy efficiency are essential parts of Sierra Club’s Beyond Coal Campaign, which is one of the national goals of the organization.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 10

Respondent: Kristin Henry, Sierra Club Counsel

Request No. 10: Please provide the following information for calendar years 2010 through 2013:

- a. The national and Kentucky budgets for the “Beyond Coal” campaign.
- b. The national and Kentucky actual expenditures for the “Beyond Coal” campaign.
- c. The national and Kentucky budgets of the Sierra Club and the Cumberland Chapter for programs directly promoting demand-side management and energy efficiency programs.
- d. The national and Kentucky actual expenditures of the Sierra Club and Cumberland Chapter for programs directly promoting demand-side management and energy efficiency programs.

Response No. 10:

Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope of this proceeding and is not “reasonably calculated to lead to the discovery of admissible evidence,” Kentucky Civil Rule 26.02(1). Sierra Club objects to this request as it calls for disclosure of its trade secrets and/or confidential and proprietary commercial and financial information. Sierra Club also objects to this request as it impinges on Sierra Club’s and possibly others’ First Amendment rights and privileges.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 11

Respondents: Kristin Henry, Sierra Club Counsel and Tyler Comings

Request No. 11: Please provide a copy of the contract, memorandum of understanding, or other documentation between the Sierra Club and Synapse Energy Economics, Inc. ("Synapse") related to the analysis and testimony performed in conjunction with this case. Specifically, provide the sections of the applicable documents that govern the analysis to be performed by Synapse.

- a. Was Synapse directed by the Sierra Club to produce a totally independent and objective analysis of the proposed EKPC Cooper Unit 1 project or was Synapse directed by the Sierra Club to produce an analysis that conformed with and complimented the "Beyond Coal" campaign? Please explain the response in detail.

Response No. 11: Sierra Club objects on the grounds that the contract between Sierra Club and Synapse Energy Economics, Inc. is privileged. Subject to and without waiving the foregoing objections, Sierra Club states that it has agreed to pay Synapse \$44,780 for work on this docket. (Kristin Henry)

- a. Yes. Sierra Club asked Synapse to independently review the Company's filing and submit testimony based on its analysis. (Tyler Comings)

Request No. 12: Please describe any affiliated relationships between the Sierra Club and Synapse Affiliated relationships can include, but are not limited to:

- b. Investment in Synapse by the Sierra Club.
- c. Corporate ownership of Synapse in total or part by the Sierra Club.
- d. Officers and officials of the Sierra Club holding seats on the Synapse board of directors.

Response No. 12:

- a. None.
- b. None.
- c. None.

Request No. 13: Please refer to page 1 of the Comings Direct Testimony and Exhibit TFC-1.

- a. It appears that Mr. Comings' work experience, training, and educational background has been primarily focused in the areas of mathematics and economics. Is this correct?
- b. Does Mr. Comings have any work experience, training, or educational background in the fields of electrical or environmental engineering? If yes, please describe.
- c. On page 1 Mr. Comings states he performed an economic impact analysis for a proposed Renewable Portfolio and Efficiency Standard in Kentucky for Mountain Association for Community Economic Development. However, Mr. Comings' profile on http://www.synapse-energy.com/expertise/staff_comings.shtml states "At Synapse, Mr. Comings has performed economic impact modeling for Vermont's Comprehensive Energy Plan and its energy efficiency investments, and for Kentucky's renewable and energy efficiency portfolio standard." Would Mr. Comings agree that to date Kentucky has not adopted nor established a renewable and energy efficiency portfolio standard?
- d. Refer to Exhibit TFC-1. For the period 2005 through 2010, please provide a detailed listing of all the renewable energy projects or other energy-related projects Mr. Comings worked, the duration of each project, and the status of each project.

Response No. 13:

- a. Yes.
- b. No.
- c. Yes. The Synapse website's staff biography for Mr. Comings has been changed to add the word "proposed" to the quote above. Mr. Comings' testimony has not been changed since it was accurate.
- d. This information is provided in Exhibit TFC-1, the Synapse website and the EDR Group website.

Request No. 14: Refer to page 2 of the Comings Direct Testimony.

- a. Please provide a copy of Mr. Coming's testimony before the Indiana Regulatory Commission in Cause No. 44339.
- b. Please identify every regulatory proceeding where Mr. Comings has been a witness. Include the state commission, the case number and styling, the date Mr. Comings' testimony was provided, and a copy of that testimony. If a final decision has been issued in any of these other proceedings, please include a copy of the commission's final decision.

Response No. 14:

- a. This testimony is provided as Attachment 14a.
- b. See response (a). Mr. Comings has not submitted testimony in any other cases besides the current case and IURC Cause 44339. The Commission's decision on the latter case is pending.

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER &)
LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION,)
FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC)
CONVENIENCE AND NECESSITY FOR THE)
CONSTRUCTION OF A COMBINED CYCLE GAS)
TURBINE GENERATION FACILITY ("CCGT"); (2))
ISSUANCE OF A CERTIFICATE OF PUBLIC)
CONVENIENCE AND NECESSITY TO CONVERT COAL)
FIRED GENERATING FACILITIES TO GAS; (3))
APPROVAL OF THE CONSTRUCTION OF)
TRANSMISSION, PIPELINE AND OTHER FACILITIES; (4))
APPROVAL OF ASSOCIATED RATE MAKING AND)
CAUSE NO. 44339 ACCOUNTING TREATMENT; (5))
AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS)
INCURRED DURING CONSTRUCTION AND)
OPERATION OF THE GAS REFUELING PROJECT)
THROUGH IPL'S ENVIRONMENTAL COMPLIANCE)
COST RECOVERY ADJUSTMENT; (6) AUTHORITY TO)
CREATE REGULATORY ASSETS TO RECORD (A) 20%)
OF THE REVENUE REQUIREMENT FOR COSTS,)
INCLUDING, CAPITAL, OPERATING, MAINTENANCE,)
DEPRECIATION TAX AND FINANCING COSTS ON THE)
REFUELING PROJECT WITH CARRYING COSTS AND (B))
POST-IN-SERVICE ALLOWANCE FOR FUNDS USED)
DURING CONSTRUCTION, BOTH DEBT AND EQUITY,)
AND DEFERRED DEPRECIATION ASSOCIATED WITH)
THE PROJECTS UNTIL SUCH COSTS ARE REFLECTED)
IN RETAIL ELECTRIC RATES; AND (7) ISSUANCE)
OF A NECESSITY CERTIFICATE TO TRANSPORT)
NATURAL GAS IN INDIANA)

CAUSE NO. 44339

Direct Testimony of
Tyler Comings

Public Version

On Behalf of
Citizens Action Coalition of Indiana

August 22, 2013

1 **1. INTRODUCTION AND PURPOSE OF TESTIMONY**

2 **Q Please state your name, business address, and position.**

3 **A** My name is Tyler Comings. I am an Associate with Synapse Energy Economics,
4 Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in
5 Cambridge, Massachusetts.

6 **Q Please describe Synapse Energy Economics.**

7 **A** Synapse Energy Economics is a research and consulting firm specializing in
8 energy and environmental issues, including electric generation, transmission and
9 distribution system reliability, ratemaking and rate design, electric industry
10 restructuring and market power, electricity market prices, stranded costs,
11 efficiency, renewable energy, environmental quality, and nuclear power.

12 **Q Please summarize your work experience and educational background.**

13 **A** I have eight years of experience in economic research and consulting. At Synapse,
14 I have worked extensively on the energy planning sector including economic
15 impact analyses for Vermont Energy Efficiency programs for the Vermont
16 Department of Public Service, a proposed Renewable Portfolio and Efficiency
17 Standard in Kentucky for Mountain Association for Community Economic
18 Development (MACED), a “Beyond Business as Usual” energy future for the
19 U.S. for Civil Society Institute (CSI) and a proposed carbon standard for Natural
20 Resources Defense Council (NRDC). I have worked on several cases involving
21 coal and gas plant economics. I have provided consulting services for various
22 other clients including: Sierra Club, EarthJustice, Consumers Union, Energy
23 Future Coalition, American Association of Retired Persons, and Massachusetts
24 Energy Efficiency Advisory Council.

25 Prior to joining Synapse, I performed research in consumer finance for ideas42
26 and economic analysis of transportation and energy investments at Economic
27 Development Research Group.

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1 I hold a B.A. in Mathematics and Economics from Boston University and a M.A.
2 in Economics from Tufts University.

3 My full resume is attached as Exhibit TFC-1.

4 **Q On whose behalf are you testifying in this case?**

5 **A** I am testifying on behalf of Citizens Action Coalition of Indiana.

6 **Q Have you testified in front of the Indiana Utility Regulatory Commission**
7 **previously?**

8 **A** No, I have not.

9 **Q What is the purpose of your testimony?**

10 **A** Dr. Jeremy Fisher and I were hired by Citizens Action Coalition of Indiana to
11 review Indianapolis Power and Light's (IPL or the Company) application for the
12 issuance of a certificate of public convenience and necessity (CPCN) for a new
13 natural gas combined cycle (CC) plant at Eagle Valley and re-fueling of Harding
14 Street Units 5 and 6 to natural gas.

15 My testimony focuses on the assumptions for available capacity, capacity prices
16 and peak load forecasts used in the Company's analysis supporting the CPCN for
17 the Eagle Valley CC and testimony by Witness Herman Schkabra. I also briefly
18 discuss the treatment of off-system sales profits and the Company's finances as
19 raised by Witness Kelly Huntington. My colleague, Dr. Fisher, evaluates the
20 assumptions and methodology of the Company's modeling and offers future
21 recommendations.

22 **Q How much is the Company proposing to spend on the Eagle Valley CC for**
23 **operation in 2018?**

24 **A** According to Witness Crawford, the plant is estimated to cost \$631 million,
25 excluding financing.¹

¹ Crawford Direct Testimony, page 16 line 4

1 **Q What are your findings regarding the Company's application?**

2 **A** The Company's application provides insufficient justification for construction of
3 the new Eagle Valley CC in 2018 for the following reasons:

- 4 1. The Company overestimates their capacity need in modeling future
5 resource plans.
- 6 2. Using the Company's more up-to-date capacity price forecasts
7 would favor delaying the new natural gas CC until 2020.
- 8 3. The more up-to-date capacity price forecasts are still likely too
9 high given the supply conditions in MISO.
- 10 4. The Company's modeling treats off-systems sales profits from
11 their resource plans as if they were passed on to ratepayers when,
12 in reality, they all go to IP&L, or its parent company's (AES)
13 shareholders.
- 14 5. The project represents an unnecessary financial risk for ratepayers
15 at this time.

16 **Q Did you perform any alternative analysis for the Company's results?**

17 **A** Yes, I performed an alternative estimate of present value revenue requirements
18 (PVRR) for the two resource plans involving the construction of a new 600 MW
19 natural gas CC using the Company's more up-to-date capacity price forecasts.

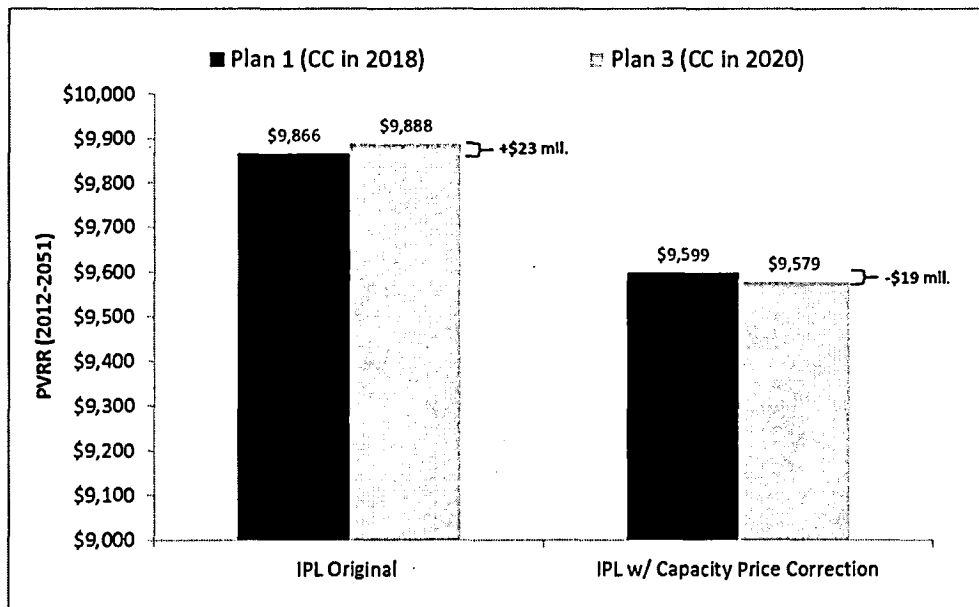
20 **Q Are capacity prices a key determinant of the PVRR for the resource plans in
21 the Company's modeling?**

22 **A** Yes. The Company assumes that if it is short on capacity relative to its reserve
23 requirement, it will buy capacity from the market—either through a contract or on
24 the MISO market. The cost of these purchases is determined by the Company's
25 assumption for the capacity price, multiplied by the amount of capacity
26 purchased.

1 Q What are the results of your analysis?

2 A Simply substituting the more up-to-date capacity price projection from the
 3 Company changes the outcome and the preferred alternative. Figure 1 shows the
 4 Company's original base case PVRR estimates for building a new natural gas CC
 5 in 2018 and 2020—Resource Plans 1 (in black) and 3 (in light blue), respectively.
 6 The use of older, higher capacity price forecasts leads to a higher PVRR (\$23
 7 million difference) for building the CC for operation in 2020 compared to 2018.²

8 Substituting more up-to-date capacity prices results in a reduction in PVRR--
 9 relative to the Company's original results--of \$267 million for Plan 1 and \$309
 10 million for Plan 3 in the base case. The results show that delaying the build of the
 11 new CC until 2020 is now more favorable than the Company's chosen strategy of
 12 building it for operation in 2018 (\$19 million lower than building in 2018).
 13 Further detail on this analysis is provided subsequently in my testimony.



14

15 **Figure 1: Base Case PVRR Results for Resource Plans 1 and 3 with Capacity Price**
 16 **Corrections³**

² IPL Public Workpapers, IRP11_CPCN_Plan_Results_40_Years.xlsx, Base tab

³ Source: CAC DR 4-5, Confidential Attachment 1 (CPCN1 Annual Income Statement 20130709), calculations of updated results by Synapse

1 **2. OVERVIEW OF THE COMPANY’S ECONOMIC ANALYSIS**

2 **Q How did the Company choose the option to build a new natural gas plant at**
3 **Eagle Valley?**

4 **A As discussed by Witness Schkabla, in the initial phase of modeling (Witness**
5 **Fisher and I will refer to this as “CPCN Phase 1”), the Company modeled six**
6 **resource plans for acquiring additional capacity with varying years for starting**
7 **operations, including:⁴**

- 8 1. 600 MW CCGT in 2018
- 9 2. 550 MW CT and 500 MW of Wind in 2018
- 10 3. 600 MW CCGT in 2020
- 11 4. 550 MW CT and 500 MW of Wind in 2020
- 12 5. 600 MW Supercritical pulverized coal in 2020
- 13 6. 600 MW Nuclear in 2020

14

15 These six plans all comprise 600 MW of capacity credit. (Due to its intermittent
16 availability, wind receives a 10% capacity credit in MISO). The Company
17 modeled these six resource plans using the Ventyx Midas model to estimate the
18 plan with the lowest present value revenue requirement (PVRR). Resource Plan 1
19 (a new 600 MW CCGT in 2018) resulted in the lowest PVRR in their base case.⁵

20 The Company used this result to develop an RFP for a new natural gas CC to be
21 built in 2018. They then performed a second phase of modeling congestion costs
22 using the PROMOD IV model and combined that with Midas modeling, resulting
23 in a PVRR comparison of the costs of bids that the Company received, along with
24 the Eagle Valley CCGT or “self-build option” (Witness Fisher and I will refer to
25 this as “CPCN Phase 2”).⁶

⁴ Direct Testimony of Herman Schkabla, page 5, line 6.

⁵ Direct Testimony of Herman Schkabla, page 10, line 8.

⁶ Direct Testimony of Herman Schkabla, page 13, line 5.

- 1 **Q** How did the Company choose to model the six resource scenarios listed
2 above?
- 3 **A** These six resource plans modeled in this filing are identical to the “2011 IRP
4 Scenario Resource Plans” from the Company’s 2011 Integrated Resource Plan
5 (IRP).⁷
- 6 **Q** Has the Company updated these six resource plans since the IRP from two
7 years ago?
- 8 **A** No, they have not.
- 9 **Q** Has the Company updated the alternate future scenarios that were used in
10 the IRP for purposes of modeling in this filing?
- 11 **A** To some extent. The Company has modeled sensitivities for low gas prices, high
12 gas prices and a “moderate environmental” scenario as they did in their 2011 IRP.
13 However, the IRP included other scenarios that were not modeled in this filing
14 such as an “environmental scenario” which has a carbon cost that is both higher
15 and starts earlier than the “moderate environmental scenario.”
- 16 **Q** Has the Company used consistent modeling assumptions in CPCN Phase 1
17 and Phase 2?
- 18 **A** No. As I will explain in subsequent sections of my testimony, the Company used
19 inconsistent assumptions for capacity prices and the amount of capacity available
20 between the two phases of modeling. For instance, they included the 200 MW
21 capacity from Harding Street Unit 5 and 6 in their CPCN Phase 2 modeling but
22 not in CPCN Phase 1.⁸
- 23 **Q** Which phase of modeling used the most up-to-date assumptions?
- 24 **A** CPCN Phase 2 modeling--which evaluated different bids for natural gas CC
25 construction--used more up-to-date assumptions for demand response, capacity
26 price forecasts, and included the available capacity from the Harding Street re-

⁷ Direct Testimony of Herman Schkabla, page 5, lines 3-7.

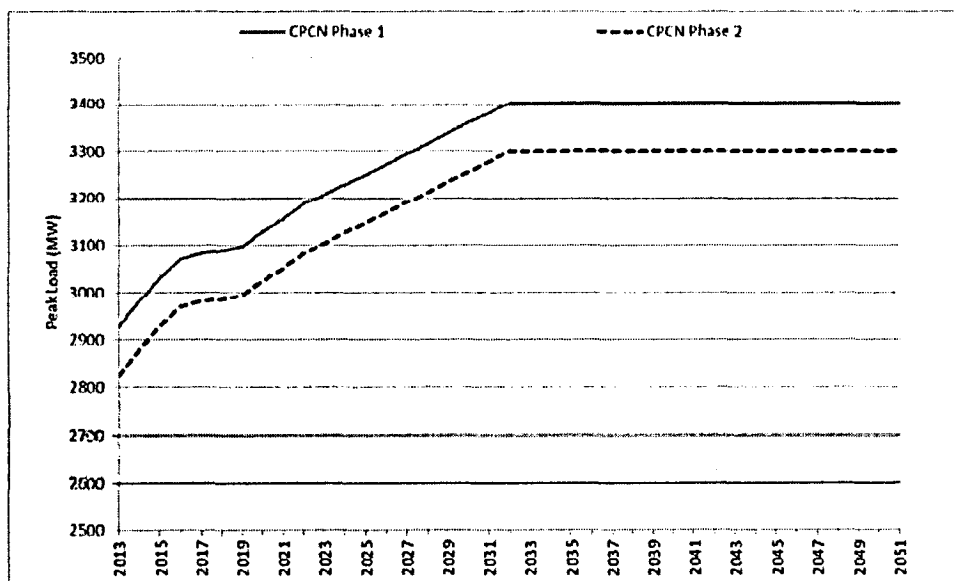
⁸ Based on a comparison of CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal data.

1 fueling projects. However, CPCN Phase 1 modeling—which evaluated the type of
 2 resource plan to choose in the first place—used older, higher capacity price
 3 forecasts, lower demand response forecasts and did not include the Harding Street
 4 re-fueling capacity. Witness Fisher discusses other inconsistencies between the
 5 two modeling phases.

6 **3. THE COMPANY OVERESTIMATES CAPACITY NEED WHEN CHOOSING A RESOURCE**
 7 **PLAN**

8 **Q Did the Company consistently model the impacts of demand response in this**
 9 **filing?**

10 **A** No, the Company included additional demand response in their modeling of the
 11 CC build options (“CPCN Phase 2”) but not in their resource plan modeling
 12 (“CPCN Phase 1”). Figure 2 shows this discrepancy which accounts for 103 MW
 13 of peak load that was unnecessarily included in their estimate of capacity need
 14 when estimating the PVRR of their six resource plans.⁹



15

16
 17

Figure 2: IPL Peak Load Forecasts (after DSM) used in CPCN1 and BCPCN modeling¹⁰

⁹ Data Response CAC 4.4, Attachment 1

¹⁰ Source: CAC DR 4-4, Attachment 1 (CPCN1 Transact C Monthly Summary 20130709)

1 **Q Has the Company acknowledged this discrepancy in peak load assumptions**
2 **between the two phases?**

3 **A** Yes, the Company acknowledged this discrepancy:

4 Although the omission of the Demand Response programs for the
5 CPCN1 analysis will effectively increase the amount of capacity
6 purchases and associated capacity expense for the six plans
7 modeled, the additional capacity expense will be the same for each
8 plan and will not change the relative PVRP results.¹¹

9 **Q Do you agree with the Company's statement above?**

10 **A** I agree that, given the way the Company has modeled the six resource plans,
11 changing the peak load would not change the ranking of the least cost plans. This
12 is simply an artifact of the Company's capacity need being fixed at 600 MW.
13 However, the point is that the exclusion of over 100 MW of demand response in
14 resource planning means the Company is over-procuring capacity. Modeling a
15 lower capacity need may indeed result in a different choice for the Company but
16 there is no way to know this unless the analysis is consistent and up-to-date.

17 **Q Did the Company consistently model the re-fueling projects at Harding**
18 **Street Units 5 and 6?**

19 **A** No, the Company included these projects in their modeling of the CC build
20 options (Phase 2) but not in their resource plan modeling (Phase 1). This omission
21 accounts for 200 MW of additional capacity that should have been available in the
22 Phase 1 modeling.¹²

23 **Q Are the missing demand response and re-fueling projects the only**
24 **discrepancies in the capacity modeled in both phases?**

25 **A** No. In Confidential Figure 3, I show the differences in capacity available in Phase 1
26 and Phase 2 modeling. The capacity available in both models varies for several
27 other reasons, including: 1) the Petersburg coal units have different capacity
28 ratings in Phase 1 and 2; 2) additional wind resources of 200 MW are not

¹¹ Data Response CAC 4.4 (Exhibit TFC -2)

¹² Direct Testimony of Kevin Crawford, page 4, line 20 discusses mentions "200 – 210 MW after re-fueling" when discussing the Harding Street 5 and 6 projects.

1 available in Phase 1 but are in Phase 2; and 3) the gas CC comes on-line in
 2 different years (2018 in Phase 1 and 2017 in Phase 2).¹³

3 Phase 2 (the dashed line) modeling includes 292 MW more capacity than Phase 1
 4 (the solid line) from 2018 through 2031 and 92 MW more capacity from 2032
 5 through 2051. This drop in the difference in capacity (between the two phases) in
 6 2032 occurs because the 200 MW from Harding Street re-fueling Units 5 and 6 go
 7 off-line in 2032.



8

9 **Confidential Figure 3: Available Capacity in Phase 1 (CC in 2018) and Phase 2**
 10 **(Chosen CC build) Modeling¹⁴**

11 **Q Does the inconsistency in available capacity overlap with the lack of 103 MW**
 12 **of demand response in the Company’s Phase 1 modeling?**

13 **A** No, the effects from these inconsistencies are additive. The additional demand
 14 response lowers the peak load requirement and resulting need for capacity by 103
 15 MW. Confidential Figure 3 above shows 292 MW of available capacity included in
 16 Phase 2 that is not in Phase 1. This, along with the 103 MW of peak load
 17 reduction from demand response, means that Phase 1 underestimates available
 18 capacity by 395 MW. Originally, the Company was assuming a capacity need of

¹³ Based on a comparison of CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal data.

¹⁴ Source: CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal tab.

1 600 MW in their Phase 1 modeling but the proper accounting of available
2 capacity resources would mean a capacity requirement of less than half of that.

3 **Q Should the Company have assumed a capacity need of 600 MW in their**
4 **Phase 1 modeling?**

5 **A No. The Company clearly omitted several key resources including demand**
6 **response and the Harding Street re-fueling projects when modeling resource**
7 **plans. The Company should properly re-evaluate its capacity need, perform**
8 **modeling to meet this much lower requirement and ensure that its modeling is**
9 **internally consistent.**

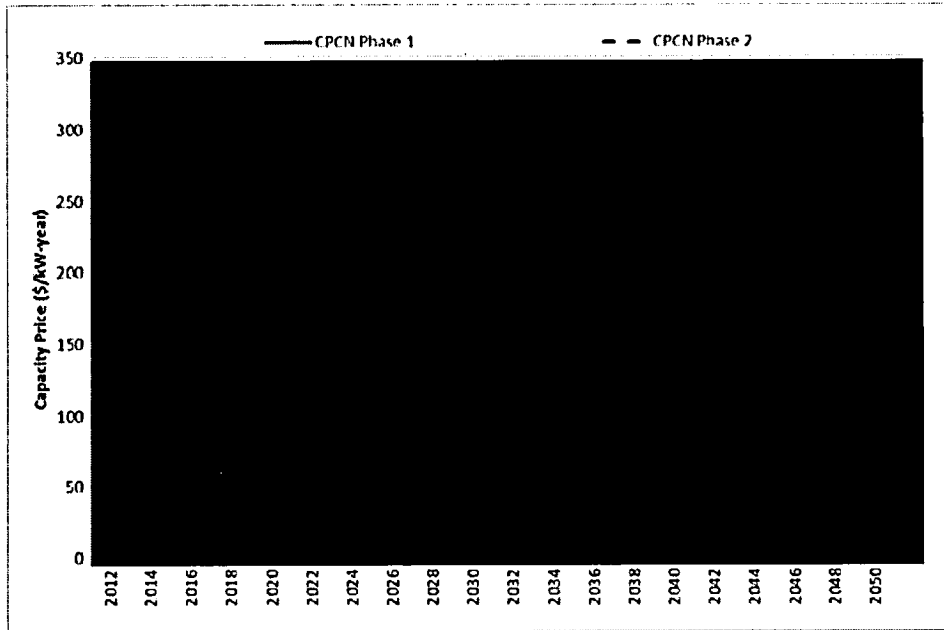
10 **4. USING THE COMPANY'S MORE UP-TO-DATE CAPACITY PRICE FORECASTS WOULD**
11 **RESULT IN DELAYING BUILDING A NEW NATURAL GAS CC UNTIL 2020.**

12 **Q Please explain the inconsistent capacity price forecasts used in the**
13 **Company's modeling.**

14 **A In Phase 1 of the CPCN, when the Company was choosing the best resource plan,**
15 **they used the same capacity prices from their 2011 IRP. However, in Phase 2,**
16 **they used an updated capacity price forecast based on an adjustment to Ventyx's**
17 **Spring 2012 Reference Case forecast assumptions.¹⁵**

18 Confidential Figure 4 shows the Company's most up-to-date capacity price forecast
19 assumptions used in Phase 2 modeling compared to those used in Phase 1.

¹⁵ CAC DR 4-5, Confidential Attachment 2 (Ventyx Documentation for Capacity Prices_Investment Component) (Exhibit TFC-3)



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Confidential Figure 4: IPL Capacity Price Forecasts in CPCN Phases 1 and 2 (\$/kW-year)¹⁶

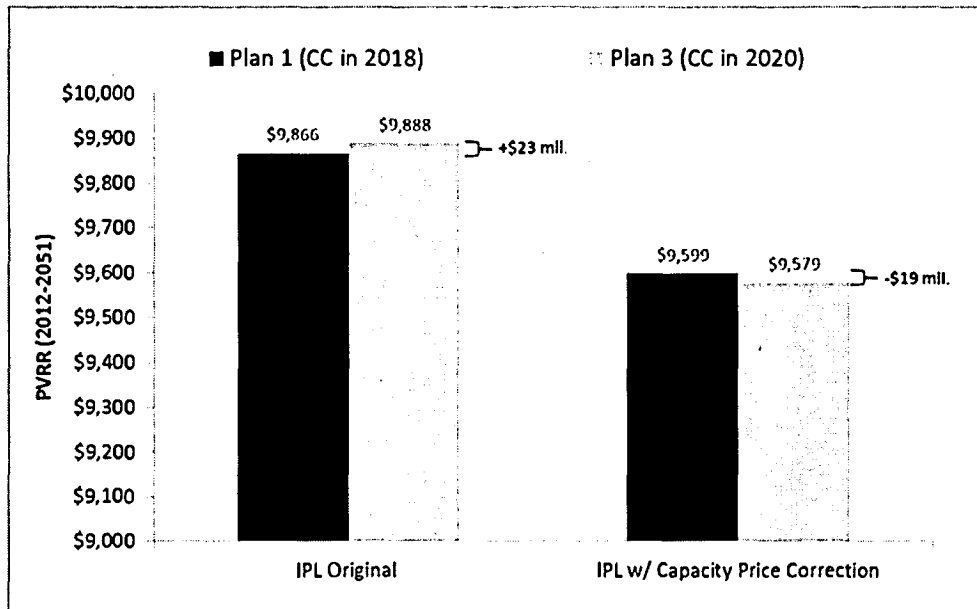
5 **Q**
6

Does using the more up-to-date capacity price forecast change the ranking of the resource plans in terms of lowest PVRR?

7
8
9
10
11
12
13

Yes. I performed an alternative estimate of present value revenue requirements for both of the Company’s resource plans involving a new gas CC plant—shown in Figure 5, below. The Company concluded that building a CC in 2020 (in light blue) had a \$23 million higher PVRR than building it in 2018 (in black). However, using the Company’s more up-to-date capacity price forecasts, the updated results show that delaying the build until 2020 is more favorable than building it in 2018, now with a \$19 million lower PVRR.

¹⁶ Source: CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal tab.



1

2

3

Figure 5: Base Case PVRR Results for Resource Plans 1 and 3 with Capacity Price Corrections¹⁷

4 Q

5

Are you recommending that the Company plan on building a new natural gas CC in 2020?

6 A

7

8

9

10

11

12

No. Correcting for the Company's use of inconsistent capacity price forecasts in the filing shows that delaying the build of the CC is the most economically viable scenario given the Company's current modeling structure. However, as I discussed earlier, and as discussed by my colleague Dr. Fisher, there are other issues of concern regarding the Company's analysis that suggest further flaws in their modeling and, by extension, choice of resource plan. Dr. Fisher presents more detailed recommendations for the Company going forward.

13

14

5. THE COMPANY'S MORE UP-TO-DATE CAPACITY PRICE FORECASTS ARE LIKELY TOO HIGH GIVEN THE SUPPLY CONDITIONS IN MISO.

15 Q

Please summarize the Company's treatment of capacity prices.

16 A

17

In Phase 2, the Company uses the Ventyx Spring 2012 Reference Case capacity price forecast with some adjustments by the Company including for "tightening

¹⁷ Source: CAC DR 4-5, Confidential Attachment 1 (CPCN1 Annual Income Statement 20130709), calculations of updated results by Synapse

1 supply and demand due to retirement of coal units for EPA MATS [Mercury Air
2 Toxics Standard] compliance.”¹⁸

3 **Q Has MISO evaluated the effect of coal retirements on capacity in the RTO?**

4 **A** Yes, the 2012 MISO Transmission Expansion Planning (MTEP) resource
5 adequacy analysis reported that MISO currently has over 112 GW of internal
6 summer rated capacity. MTEP projects between 2241 MW and 9912 MW of coal
7 retirement due to environmental regulations, and between 2710 MW and 7407
8 MW of new capacity to be built. This leads them to a range between 110 GW and
9 122 GW of total capacity that will be available in MISO in 2022,¹⁹ assuming no
10 unanticipated additions or retirements. The report concludes that with the
11 maximum amount of coal retirements, projections of new capacity additions, and
12 additional demand response that:

13 Given the projections for both GIQ [Generator Interconnection
14 Queue] projects and DR growth in MISO in this assessment, MISO
15 expects that this will not be problematic, and that MISO’s planning
16 reserve margin requirement will be met during the 10th-year
17 peak.²⁰

18 **Q Is it reasonable to assume that MISO capacity could be available at a price
19 below the Company’s forecast?**

20 **A** Yes. The most recent clearing price for capacity in MISO was \$1.05 per kW-
21 year.²¹ If the capacity prices in MISO continue to be lower than the cost of
22 building or procuring new capacity, then it may be advantageous for the Company
23 to purchase a fraction of their capacity, in the short-term, if they are able to meet
24 their energy requirements.

¹⁸ CONFIDENTIAL Schkabra WP 5 (Update to Midwest_Spring 2012_Power_Reference_Case_-
_Data_Supplement_IPL).xlsx

¹⁹ MISO Transmission Expansion Planning 2012. Chapter Six, page 73 (Exhibit TFC-4)

²⁰ MISO Transmission Expansion Planning 2012. Chapter Six, page 69 (Exhibit TFC-4)

²¹ CAC DR 1-35, Attachment 5 (2013-2014 MISO Planning Resource Auction Results) (Exhibit TFC-5)

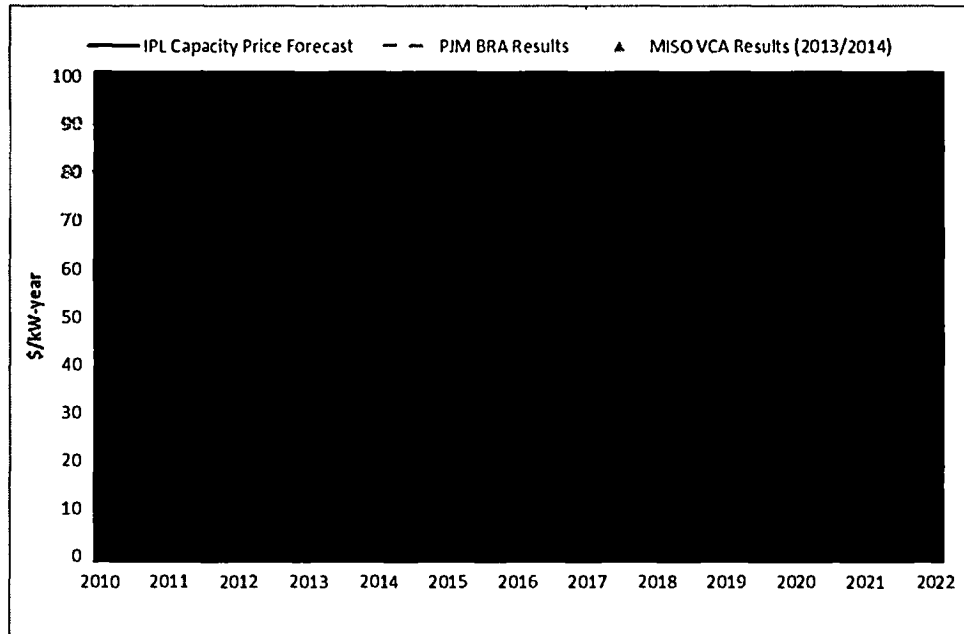
1 **Q How do the Company's up-to-date capacity price forecasts compare to**
2 **capacity prices from past auctions in MISO and PJM?**

3 **A** The capacity price increase forecasted by the Company is much higher than what
4 has occurred historically in the both MISO and PJM regions. Confidential Figure 6
5 below shows the historical auction clearing prices for PJM RTO and MISO
6 Voluntary Capacity Auction (VCA) which had its first annual capacity auction in
7 2013. This is a balance market whereby utilities are responsible for meeting their
8 reserve requirement--and typically fulfill most of this requirement with their own
9 generation--and can also purchase or sell on the VCA. The MISO VCA cleared at
10 a price of \$1.05 per kW-year in the 2013/2014 delivery year (blue triangle).²²

11 PJM's Base Residual Auction (BRA) includes all capacity that will be available in
12 the region (as opposed to the MISO market which is the balance of remaining
13 reserves that are needed) and takes bids three years ahead of time. All capacity
14 that clears the auction in the RTO for a given delivery year receives the same
15 price (which can vary by sub-regions depending on delivery constraints). This
16 market offers several years of historical data for comparison. Although the
17 clearing price has been volatile in the past years (dashed line), the price has not
18 exceeded \$64 per kW-year (for delivery year 2010/2011). The most recent PJM
19 BRA for 2016/2017 cleared at \$21.67 per kW-year (\$59.37 per MW-day using
20 PJM's convention).²³ This most recent PJM auction period captures anticipated
21 coal retirements in 2016 and 2017 yet showed a drop in capacity price. In
22 contrast, the Company's MISO capacity price forecast predicts a sharp rise to \$84
23 per kW-year in 2017.

²² CAC DR 1-35, Attachment 5 (2013-2014 MISO Planning Resource Auction Results) (Exhibit TFC-5)

²³ PJM 2016/2017 Base Residual Auction Results, page 6 (Exhibit TFC-6)



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2

3

Confidential Figure 6: Comparison of Capacity Prices from IPL, MISO²⁴ and PJM RTO Auction Clearing Prices (\$/kW-year, Calendar Year)²⁵

4 **Q**

To what does PJM attribute the most recent drop in capacity prices in the 2016/2017 auction?

5

6 **A**

According to PJM:

7

The auction clearing prices are lower than the previous auction

8

driven largely by a flat demand growth and an increase in supply

9

from substantial amount of new entry offers, uprates associated

10

with repowering existing resources to natural gas, increased

11

imports, and withdrawn deactivations.²⁶

²⁴ Source: CONFIDENTIAL Schkabra WP 1 (CPCN Modeling Assumptions_Ventyx_04_12_13 Final Rev2).xlsx, PJM 2016/2017 Base Residual Auction Results (Exhibit ____), MISO 2013/2014 Auction Results (provided in DR CAC 1-35, Attachment 1).

²⁵ PJM BRA clearing prices are reported in terms of \$/MW-day. I have converted these prices to \$/kW-year ($=\$/\text{MW-day} \times 365 \text{ (days per year)} / 1000 \text{ (kW per MW)}$) to follow the MISO convention. The MISO clearing price was for the delivery year 2013/2014, so I have shown it as the 2013 calendar year price for simplicity; the MISO 2014 calendar year price will depend on the results from the 2014/2015 auction.

²⁶ PJM 2016/2017 Base Residual Auction Results, page 2 (Exhibit TFC-6)

1 **Q Where were most of the imports of capacity located?**

2 Imports from MISO represented 4723 MW of the total 7283 MW in imports that
3 cleared the PJM 2016/2017 auction.²⁷

4 **Q How can capacity located in MISO place bids in the PJM auction?**

5 MISO capacity that has “firm transmission service” to PJM can bid into PJM’s
6 forward capacity market. However, not all generators currently have this type of
7 access.²⁸

8 **Q Why would MISO resources bid into the PJM market to provide capacity**
9 **three years in the advance?**

10 **A** If a generator in MISO bids into the PJM forward market for the 2016/2017
11 delivery year, they likely anticipate that PJM capacity prices are higher than what
12 MISO’s would be for the same delivery period since these generators have the
13 option to bid into either market.

14 **Q Would a generator have good reason to think that the most current PJM**
15 **capacity clearing price will be higher than MISO’s clearing price for delivery**
16 **in 2016/2017?**

17 **A** Yes, they would. The most recent MISO clearing price was \$1.05 per kW-year for
18 2013/2014 while PJM’s clearing price for that period was \$10.22 per kW-year.
19 Given that PJM’s most recent clearing price in 2016/2017 was \$21.67 per kW-
20 year--and incorporates coal retirements from MATS--it would be reasonable to
21 assume that the MISO price will remain lower than PJM’s in 2016 and 2017.

22 **Q How should the Company treat capacity prices in their modeling?**

23 **A** The Company has assumed that capacity prices will rapidly increase in 2017
24 above what has occurred historically in the PJM market. However, evidence from
25 the PJM forward capacity market shows that this rapid increase may not occur.

²⁷ PJM 2016/2017 Base Residual Auction Results, page 3 (Exhibit TFC-6)

²⁸ PJM 2016/2017 Base Residual Auction Results, page 3 (Exhibit TFC-6)

1 Therefore, the Company should at the very least perform a sensitivity analysis
2 assuming that capacity prices in MISO do not rise sharply in 2017.

3 6. **THE COMPANY'S MODELING TREATS OFF-SYSTEMS SALES PROFITS AS IF THEY**
4 **WERE PASSED ON TO RATEPAYERS WHEN, IN REALITY, PROFITS ALL GO TO**
5 **COMPANY SHAREHOLDERS**

6 **Q Is it reasonable that Company's modeling assumes that they are able to sell**
7 **energy off-system?**

8 **A Yes.**

9 **Q Does the Company's modeling assume that the profits from off-system sales**
10 **accrue to ratepayers?**

11 **A Yes, implicitly. The Company counts all sales from both retail and off-system**
12 **sales as a benefit to ratepayers in their modeling.**

13 **Q Is it the Company's standard practice to share off-system sales profits with**
14 **ratepayers?**

15 **A No. As confirmed by Kevin Crawford, Senior Vice President of IPL, in hearings**
16 **for Cause 44242, the Company does not offer a sharing mechanism for these**
17 **profits:²⁹**

18 A. I apologize if I was inconsistent. My understanding is that off-
19 system sales wholesale margins do not go to the ratepayer.

20 Q. Do not?

21 A. Yes, do not.

22 Q. So they go to the shareholders?

23 A. I think that's the only other place for them to go.

24 I assume that that the Company seeks, or should seek, a least cost solution for
25 ratepayers, not an optimal solution for the Company's shareholders. Therefore,
26 the Company's modeling and analysis should review costs and benefits that flow

²⁹ IURC Cause 44242, April 24, 2013, page 79 lines 6 to 12 of hearing transcript (Exhibit TFC-7).

1 to ratepayers, and exclude those that flow to the shareholders of IP&L or its
2 parent Company, AES.

3 **Q Would removing the off-system sales affect the rankings of lowest cost PVRR**
4 **for the Company's six resource plans?**

5 **A** Possibly. This correction would certainly change the PVRR estimates themselves
6 and could change the order of lowest cost PVRR depending on the differences in
7 amount of off-system sales profits between plans.

8 **Q Given the model runs and outputs that have been made available by the**
9 **Company, is it possible to disentangle the profits from off-system sales from**
10 **revenue requirements?**

11 **A** I do not believe so. Also, Witness Adkins, who oversaw the Ventyx Midas
12 modeling in Cause 44242, was asked to remove off-system sales revenues and
13 associated production costs and could not.³⁰ If the Company wanted to model
14 appropriately, I believe they could restrict the model from offering off-system
15 sales--thus providing only the costs to ratepayers.

16 **Q Should off-system sales profits be modeled as benefitting ratepayers?**

17 **A** No. Ratepayers currently do not receive profits from off-system sales; this money
18 accrues to the Company's shareholders. Therefore, the Company modeling off-
19 system sales profits as if they lowered revenue requirements is inconsistent with
20 today's reality. This contradiction should be rectified in subsequent modeling.

21 **7. THE EAGLE VALLEY CC PROJECT REPRESENTS AN UNNECESSARY FINANCIAL**
22 **RISK FOR RATEPAYERS AT THIS TIME**

23 **Q Please explain why the filing for the CPCN for an Eagle Valley CC was**
24 **premature.**

25 **A** As I have shown, use of more up-to-date capacity prices leads to the conclusion
26 that delaying the new natural gas CC plant by two years is less costly. In addition,
27 the Company used inconsistent assumptions for peak load reduction from demand

³⁰ Cause 44242, Data Response CAC 7-4 (b) (Exhibit TFC-8)

1 response and available generating capacity, including Harding Street 5 and 6 re-
2 fueling projects.

3 The Company's modeling also includes the operation of Harding Street Unit 7
4 and Petersburg Units 1 through 4 with environmental retrofits. Thus they were
5 presuming to receive approval of the CPCN for environmental compliance
6 projects for (IURC Cause 44242) at the time of the filing. Although the CPCN
7 was approved for all units on August 14, 2013, the Company should have
8 addressed the possibility that at least one their units would not be granted a CPCN
9 (e.g. Harding Street Unit 7).


10 **Q What key financial justification has the Company provided for the**
11 **Commission to approve the CPCN for the Eagle Valley CC?**

12 **A** Witness Huntington discusses the importance of the Company's credit rating and
13 the potential risk if the CPCN for Harding Street and Eagle Valley projects are not
14 approved, claiming that, "IPL will have lower credit metrics until it receives
15 recovery of the costs through retail rates. Such lower metrics will increase the risk
16 that IPL's investment grade credit rating is downgraded."³¹

17 Witness Huntington then discusses the harm that would befall ratepayers if the
18 Company's credit rating fell to a "non-investment rating," claiming that:

19 Customers would be adversely affected because higher capital
20 costs lead to higher rates for electric service and strain resources
21 that could otherwise be utilized to meet our customers' ongoing
22 need for reliable electric service.³²

23 **Q Has the Company discussed the Eagle Valley CC project with credit rating**
24 **agencies?**

25 **A** Yes. When addressing Moody's, Standard and Poors (S&P), and Fitch Ratings ,
26 

³¹ Direct Testimony of Kelly Huntington, page 4 lines 8 through 11.

³² Direct Testimony of Kelly Huntington, page 4 line 23 to page 5 line 2.

1 [REDACTED]
 2 [REDACTED]
 3 [REDACTED].³³

4 **Q How did the Company present the merits of the investments in Eagle Valley**
 5 **and Harding Street 5 and 6 compared to replacement with market**
 6 **purchases?**

7 **A The Company showed a chart of pre-tax income [REDACTED]**
 8 [REDACTED]
 9 [REDACTED].³⁴

10 **Q Do ratepayers or the Commission bear responsibility for maintaining the**
 11 **Company’s credit rating?**

12 **A No. The Company’s shareholders are responsible for upholding their credit rating.**

13 **Q What are the financial risks for the ratepayers if the Commission approves**
 14 **the CPCN for the Eagle Valley CC?**

15 **A If the Commission approves the CPCN for Eagle Valley, the investment will be**
 16 **recovered from ratepayers whether it is a sound investment or not. If the**
 17 **Company has underestimated the PVRR of their chosen scenario, then ratepayers**
 18 **will be paying more than the Company had originally planned—potentially more**
 19 **than they would have paid given one of the other resource plans or for plans that**
 20 **were not considered.**

21 Also, the Company’s modeling of PVRR for the six resource options assumes that
 22 ratepayers will benefit from off-system sales profits, which is not the case in
 23 today’s reality.

24 Finally, as I have shown and Witness Fisher has discussed, the Company does not
 25 need to take on this investment at this time since they have overestimated their
 26 capacity need.

³³ Data Response CAC 1-10, Attachments 34 through 36.

³⁴ As an example, see slide 33 in the presentation to Fitch Ratings: Data Response CAC 1-10, Attachment

³⁶ (Confidential Exhibit TFC-9). This same slide was presented to Moody’s and Standard and Poors.

1 **8. FINDINGS**

2 **Q What conclusions follow from your analysis?**

3 **A** First, the Company should have modeled both Phase 1 and 2 with consistent
4 demand response penetrations and available capacity. The most recent modeling
5 (Phase 2) suggests less than half of the capacity need compared to what the
6 Company modeled in Phase 1 (600 MW).

7 Second, my analysis shows that the Company has not performed sufficient
8 modeling to justify the choice of building a new natural gas CC in 2018.

9 Correcting for the use of outdated capacity prices in their modeling shows that
10 delaying the investment of the Eagle Valley CC to 2020 is less costly than
11 building it for operation in 2018. The PVRR results for building the CC in 2018
12 compared to building in 2020 differed by a small enough margin (0.2%, \$23
13 million)³⁵ such that the inconsistency in capacity price forecasts was enough to
14 make delaying the decision more economical.

15 Third, even the lower capacity price forecast used by the Company assumes a
16 rapid increase in the MISO capacity clearing price that may not happen. Given
17 that capacity prices are an important determinant of the PVRR results, the
18 Company should have modeled a sensitivity assuming a more stable MISO
19 capacity market.

20 Finally, if the CPCN for the Eagle Valley CC is approved, then ratepayers would
21 be funding an investment that may or may not be financially advantageous for
22 them. Since off-system sales profits are not shared with ratepayers while the fixed
23 costs of the plant are shared, they would face all of the costs but none of the
24 upside benefits. Conversely, assuming CPCN approval and rate recovery, the
25 Company would stand to benefit from the additional profits from off-system sales
26 while recovering the fixed costs regardless of whether or not the new plant was
27 economically viable.

³⁵ IPL Public Workpapers, IRP11_CPCN_Plan_Results_40_Years.xlsx, Base tab

1 Q Does this conclude your testimony?

2 A It does.

EXHIBIT TFC-1

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, July 2011 – present.

Provides consulting services, conducts research, and performs economic impact analysis of renewable energy and energy efficiency investments. Recent work includes developing economic impacts of energy efficiency programs in Vermont and a scenario of clean energy investments for the U.S.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, and worked with top researchers in behavioral economics. Managed implementation and data analysis for a study of mitigation of default for borrowers that were at-risk of delinquency. Performed case studies for World Bank on financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Performed statistical modeling, including results on the timing of effects of highway construction on economic growth in Appalachia. Developed a unique Web-tool for the National Academy of Sciences on linkages between economic development and transportation, and presented findings to state government officials around the country. Created economic development strategies and improvements to company's economic development software tool.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs for cases at the firm.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data taken from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics and other healthcare facilities for statewide assessment.

EDUCATION

Tufts University, Medford, MA, MA Economics, 2007.

Graduate work in micro- and macroeconomics, econometrics, development economics, and international finance (Fletcher School of Law and Diplomacy).

Boston University, Boston, MA, BA Mathematics and Economics, 2002. *Cum Laude*, Dean's Scholar.

ADDITIONAL SKILLS

Software: MS Office, STATA, SPSS, SAS, REMI, IMPLAN, Mathematica

Programming: C++

Languages: Conversant in French

RELEVANT REPORTS

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, *Economic Impacts of the NRDC Carbon Standard*. Synapse Energy Economics for the Natural Resources Defense Council, June 2013.

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Resume dated July 2013.

EXHIBIT TFC-2

Data Request Citizens Action Coalition DR 4-4

See Direct Testimony of Witness Schkabra, p23, Table "W/ HSS 5-6 Refueling in 2016 and EV CCGT in 2017" and CAC DR 2-1, Confidential Attachment 4 (CPCN1), workbook "CPCN Transact C Monthly Summary 20130709." Please provide the following:

- a. Annual non-coincident peak load forecast (MW) before DSM for IPL from 2013-2051.
- b. Annual non-coincident peak load forecast (MW) after DSM for IPL from 2013-2051.
- c. Annual forecast reserve requirement (MW) for IPL from 2013-2051.
- d. Annual energy demand forecast (MWh) before DSM for IPL from 2013-2051.
- e. Annual energy demand forecast (MWh) after DSM for IPL from 2013-2051.
- f. Please explain why the "Non Coincident Peak" (column X) is different in some years for endpoints 1 and 2.

Objection:

Response:

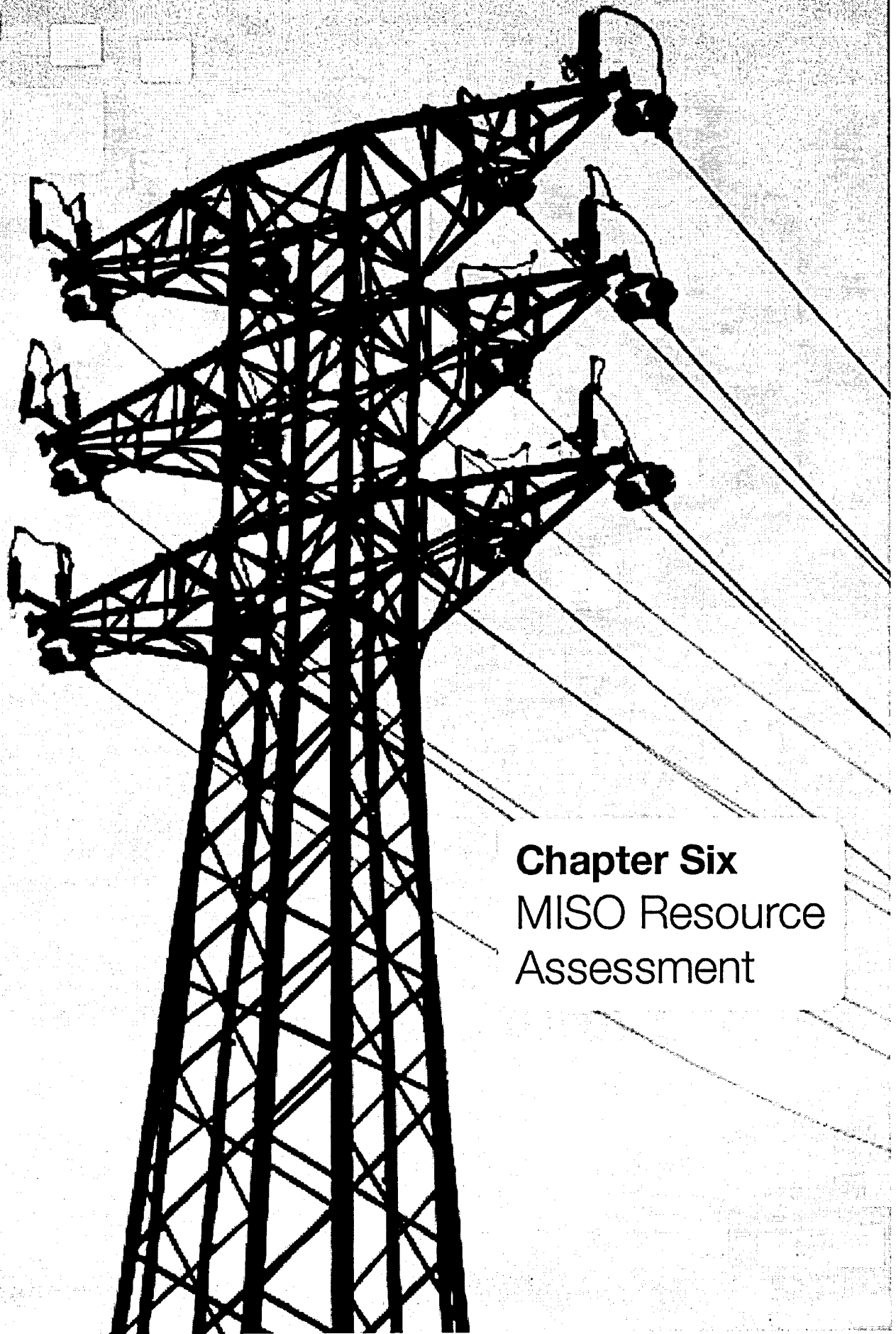
a.-f. See tab "DR 4.4 a.b.c.d.e.f." of attached spreadsheet CAC DR 4-4, Attachment 1.

The peak load and energy forecasts shown in the tables and used as input for the Midas modeling are net of energy efficiency DSM programs. For the CPCN1 workbook analysis, the peak load and energy data did not reflect 103MW of Demand Response DSM so the pre and post Demand Response forecasts are identical. The BCPCN workbook analysis did include the 103 MW of Demand Response DSM as shown in the table.

Although the omission of the Demand Response programs for the CPCN1 analysis will effectively increase the amount of capacity purchases and associated capacity expense for the six plans modeled, the additional capacity expense will be the same for each plan and will not change the relative PVRR results.

EXHIBIT TFC-3—CONFIDENTIAL

EXHIBIT TFC-4



Chapter Six
MISO Resource
Assessment

CHAPTER 6

MISO Resource Assessment

6.1 Loss of Load Expectation

As directed under Module E of the MISO Tariff, the system planning reserve is calculated by determining the amount of generation required to meet a one day in 10 years (0.1 day per year) Loss of Load Expectation (LOLE). The MISO Planning Reserve Margin (PRM) for the 2012-2013 planning year (PY) is 16.70 percent, decreasing 0.7 percentage points from 2011-2012's 17.40 percent (Figure 6.1-1). This is based on the system-wide MISO coincident load peak and resources based on its installed capacity rating, also called PRMSYSIGEN, The Planning Reserve Margin based on Unforced Capacity (PRM_UCAP) decreased from 3.81 percent to 3.79 percent, and applies to the non-coincident peak of each Load Serving Entity (LSE).

The MISO Planning Reserve Margin for the 2012-2013 planning year is 16.70 percent

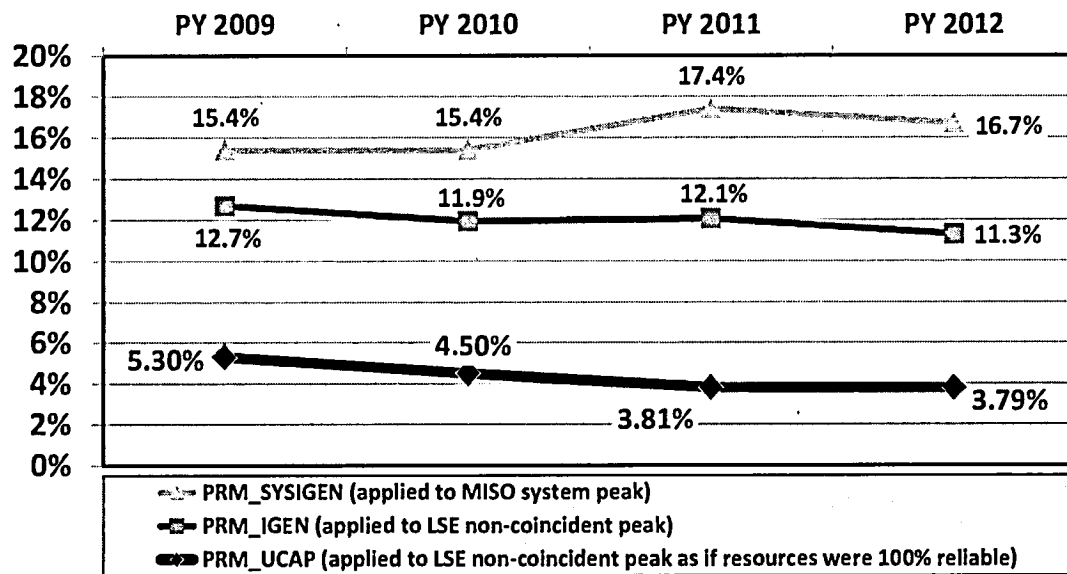


Figure 6.1-1: Comparison of recent module E PRM targets

The 0.7 percent PRMSYSIGEN decrease was the net effect of four decreasing factors and a single increasing factor. In approximate values: Decreases totaled -3.0 percent and were attributed to improved modeling of external support at -2.0 percent, lower forced outage rates at -0.7 percent, membership changes at -0.2 percent, and uncertainty of forecasting at -0.1 percent. During the summer of 2011, concern emerged that higher forced outage rates than applied in LOLE study work may be applicable to peak-load times. Therefore, an adjustment of +.2.3 percent was the single increasing factor, that when netted with the four decreasing factors, resulted in the 0.7 percent net decrease from last year.

Like last year, the 2012 MISO LOLE found no evidence of load pockets where the lack of resources would require importing more than the transmission system's ability to deliver

Like PY 2011, the PY 2012 PRM reflects no component due to transmission congestion. For example, both PY 2009 and PY 2010 had a PRM of 15.4 percent. This means, that with no congestion, PY 2009 would have been 0.6 percent marginally lower and in PY 2010 would have been 0.4 percent lower.

Benefits associated with system-wide diversity must be considered since compliance with Module E Resource Adequacy Requirements is based on representing each LSE's non-coincident monthly peak demand on the appropriate individual CPnodes. MISO determined that a diversity factor of 4.61 percent will be used for PY 2012. This is a slight increase from the 4.55 percent diversity factor used last year. After consideration for load diversity, the PRM is based on the LSE's non-coincident peak and resources based on their installed capacity rating (that is, PRMLSEIGEN), and the value is 11.32 percent (versus the no diversity 16.70 percent value).

Projected planning reserve margin requirements for 2013 through 2021 are also calculated in the LOLE Study and are utilized in Chapter 6.2 as a comparison to the projected reserves. The complete 2012 report on MISO LOLE study can be found at:

<https://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf>

6.2 Long-Term Resource Assessment

MISO aggregates individual market participant load and capacity forecasts from 2013 to 2022 to forecast long-term reserve, demand and capacity projections (2013-2022) for the MISO market footprint. MISO combines demand and capacity forecasts to predict future reserve margins and how much capacity or demand reduction would be necessary to meet system PRM requirements. Because of anticipated EPA-related retirements, the MISO region needs to add between 4,484 and 11,290 MW of new capacity, or 3,865 and 9,733 MW of demand reduction, to meet minimum PRMs in 2022, based on two different sets of analysis assumptions. MISO expects to see a 10th-year peak total internal demand between 98 GW and 120 GW depending on the demand growth rate, the diversity level, and load forecast uncertainty (LFU). MISO expects to see a 10th-year peak total available capacity between 110 GW and 122 GW depending on the impact of Attachment Y retirements and suspensions, the impact of the EPA regulations on future retirements, and the level of projects in MISO's generator interconnection queue.

Because of anticipated EPA related retirements, the MISO region needs to add between 4,484 and 11,290 MW of new capacity, or 3,865 and 9,733 MW of demand reduction to meet minimum PRMs in 2022

MISO's membership has changed since the 2011 assessment. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1, 2012. Entergy and its six utility operating companies, Entergy Arkansas, Entergy Gulf States, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans and Entergy Texas, are expected to join MISO by the end of 2013. The addition of Entergy will add approximately 15,000 miles of transmission and 30,000 MW of generation capacity into the MISO footprint. However, for the purposes of this assessment, MISO does not include Entergy demand or capacity in the projections or planning reserve margin calculations.

Forecasted Reserves

Two scenarios of the range of possibilities from the Forecasted Demand, Forecasted Capacity and Forecasted EOP Resources sections of this assessment, below, were selected and a planning reserve margin calculated for each year of the assessment from 2013 to 2022. Table 6.2-1 provides the results for both scenarios.

In both scenarios, the planning reserve margin is calculated assuming 9,912 MW of retirements occur from 2015 onward due to EPA regulations, no capacity additions from the generator interconnection queue (GIQ) are built, a diversity level of 4.61 percent is experienced across MISO's footprint, and that demand response (DR) remains constant at 2012 levels of 4,606 MW.

Scenario No. 1 uses the Module E 50/50 total internal demand of 94,279 MW and 103,584 MW for 2013 and 2022, respectively. Utilizing DR as a load modifier; this translates to a net internal demand of 89,673 MW in 2013 and 98,978 MW in 2022. The results indicate that either 4,484 MW of additional capacity will have to be built, that 3,865 MW of additional DR programs will have to register as Module E load-modifying resources, or a combination of the two. Given the projections for both GIQ projects and DR growth in MISO in this assessment, MISO expects that this will not be problematic, and that MISO's planning reserve margin requirement will be met during the 10th-year peak.

Scenario No. 2 uses the Module E 90/10 total internal demand of 99,620 MW and 109,452 MW for 2013 and 2022, respectively. Utilizing DR as a load modifier; this translates to a net internal demand of 95,014 MW in 2013 and 104,846 MW in 2022. The results indicate that either 11,290 MW of additional capacity will have to be built, that 9,733 MW of additional DR programs will have to register as Module E load-modifying resources, or a combination of the two. Given the projections for both GIQ projects and DR growth in MISO in this assessment, either some GIQ projects that are in a withdrawn study status will have to become active and built within the next ten years or DR programs will have to increase from their current levels in MISO to maintain MISO's system planning reserve margin requirement.

| Scenario | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|-------------------------------|--|------|------|-------|-------|-------|-------|-------|-------|--------|--------|
| Scenario No. 1 (50/50 demand) | Reserve Margin (percent) | 33.1 | 30.6 | 19.5 | 18.4 | 17.2 | 16.1 | 15.0 | 13.8 | 12.6 | 11.5 |
| | Planning Reserve Margin Requirement (percent) | 16.6 | 16.5 | 16.4 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 |
| | Additional Capacity to meet Requirement (MW) | - | - | - | - | - | - | 981 | 2,101 | 3,294 | 4,484 |
| | Additional Demand Reduction to meet requirement (MW) | - | - | - | - | - | - | 846 | 1,811 | 2,840 | 3,865 |
| Scenario No. 2 (90/10 demand) | Reserve Margin (percent) | 25.6 | 23.2 | 12.8 | 11.7 | 10.6 | 9.6 | 8.5 | 7.5 | 6.3 | 5.2 |
| | Planning Reserve Margin Requirement (percent) | 16.6 | 16.5 | 16.4 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 | 16.3 |
| | Additional Capacity to meet requirement (MW) | - | - | 3,133 | 4,213 | 5,338 | 6,420 | 7,589 | 8,772 | 10,033 | 11,290 |
| | Additional Demand Reduction to meet requirement (MW) | - | - | 2,701 | 3,632 | 4,602 | 5,534 | 6,542 | 7,562 | 8,649 | 9,733 |

Table 6.2-1: 2013-2022 Forecasted Reserve Scenarios¹²

Forecasted Demand

MISO expects to see a 10th-year peak total internal demand between 98 GW and 120 GW depending on the demand growth rate, the diversity level, and load forecast uncertainty (LFU) (Figure 6.2-1). Table 6.2-2 provides the total internal demand projections throughout the 10-year assessment period.

The 10th-year 50/50 peak total internal demand forecast utilizing a BAU growth rate and 4.61 percent diversity is 103,584 MW

¹² Demand reduction MWs are not equivalent to capacity addition MWs because demand affects both the numerator and denominator of the planning reserve margin calculation.

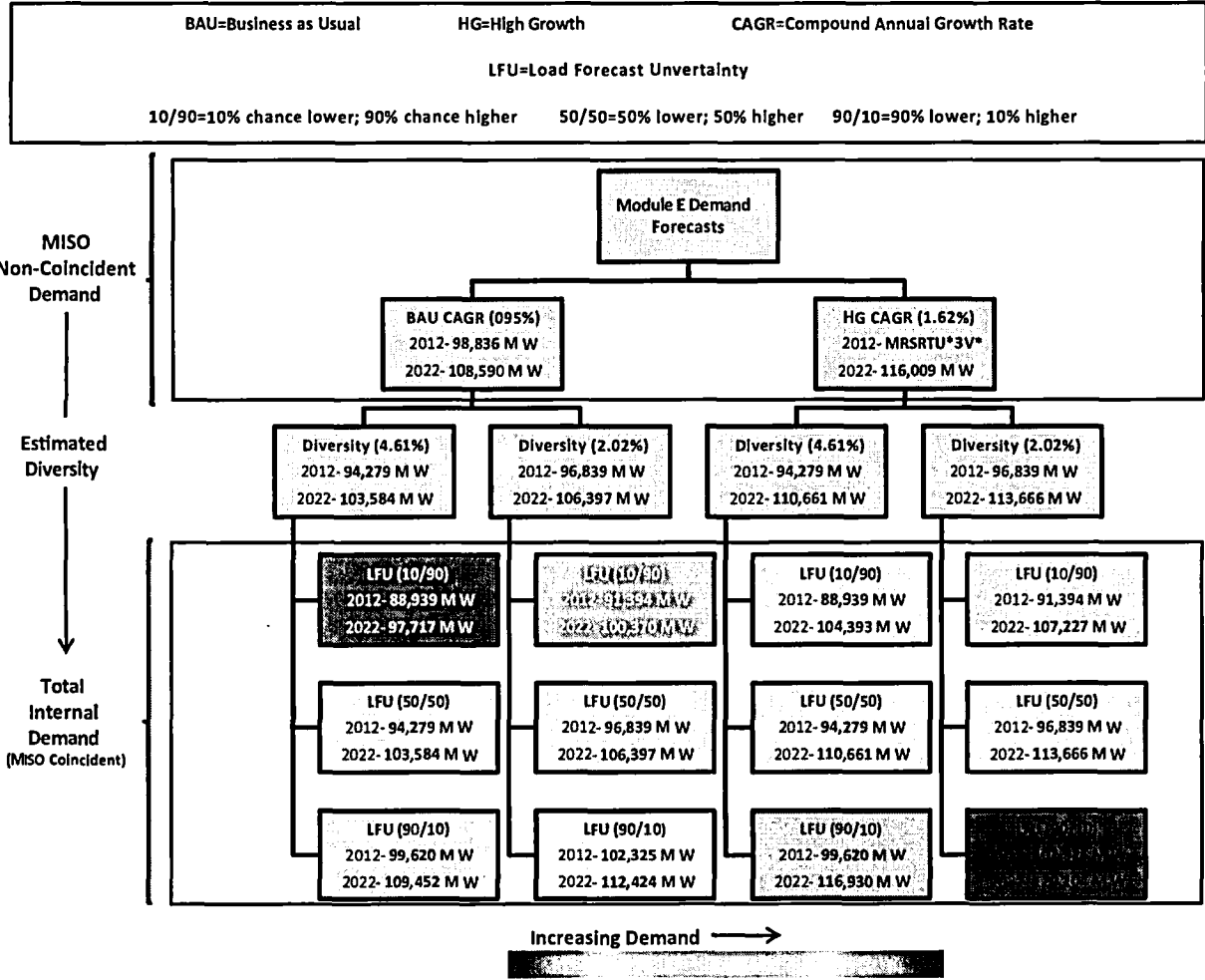


Figure 6.2-1: Forecasted Demand Decision Tree

| Growth Rate | Total Internal Peak Demand, MW Range | | | | | | | | | |
|--------------------------|--------------------------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Module E (BAU) | 88,939 | 90,684 | 91,439 | 92,270 | 93,136 | 93,968 | 94,868 | 95,779 | 96,749 | 97,717 |
| | 102,325 | 104,332 | 105,200 | 106,157 | 107,154 | 108,111 | 109,146 | 110,194 | 111,311 | 112,424 |
| High Growth Rate (1.62%) | 90,375 | 101,574 | 102,420 | 103,351 | 104,321 | 105,253 | 106,261 | 107,281 | 108,368 | 109,452 |
| | 103,977 | 105,657 | 107,363 | 109,097 | 110,859 | 112,649 | 114,468 | 116,317 | 118,196 | 120,104 |

Table 6.2-2: 2013-2022 MISO Peak Demand Range

MISO's forecast is based upon the aggregation of an individual load serving entity's (LSEs) 50/50; weather normalized, non-coincident peak demand forecasts. Details regarding the collection of LSE demand forecasts are documented in section 6.4 of the business practice manual (BPM) entitled BPM011-Resource Adequacy, posted on MISO's webpage.¹³

¹³BPM011-Resource Adequacy

MISO's 50/50 non-coincident peak demand forecasts from 2012 to 2022 are labeled "Module E 50/50 (BAU)" (Table 6.2-2). Consistent with the MTEP12 futures, this is the Business as Usual demand growth rate future (BAU). It should be noted that the MTEP12 BAU is based on a 2012 forecast of 97,408 MW with a compound annual growth rate (CAGR) of 0.91 percent, which was from an earlier vintage of LSE Module E forecast data. The CAGR from the updated demand forecasts is 0.95 percent (Table 6.2-3).

For the purposes of this assessment, MISO forecasts a high-demand growth rate future at a CAGR of 1.62 percent, which is consistent with the MTEP12 high-demand growth rate. Table 6.2-3 provides MISO's high-demand growth rate forecasts for the 10-year assessment period.

| Non-Coincident Peak Demand, MW | Current Year | 10-year Assessment Period | | | | | | | | | |
|--------------------------------|--------------|---------------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Module E 50/50 (BAU) | 98,836 | 98,836 | 100,774 | 101,613 | 102,538 | 103,500 | 104,425 | 105,425 | 106,437 | 107,515 | 108,590 |
| 50/50 (High Growth) | ———— | 100,432 | 102,054 | 103,702 | 105,377 | 107,079 | 108,808 | 110,565 | 112,351 | 114,165 | 116,009 |

Table 6.2-3: 2013-2022 non-coincident 50/50 demand forecasts

In order to calculate MISO's annual 50/50 coincident total internal demand forecasts from 2013 to 2022, MISO uses two load diversity levels are applied to the non-coincident forecasts of 4.61 percent and 2.02 percent throughout the assessment period. Details regarding these two levels are documented in the 2012 Summer Resource Assessment, Section 3.2, posted on MISO's webpage.¹⁴

MISO conducts an after-the-fact assessment by commercial pricing node (CPNode) based on forecasts entered in the Module E Capacity Tracking (MECT) tool. Details regarding the assessment procedures are documented in the Resource Adequacy BPM posted on MISO's webpage. Reviewing the forecasts versus actual peak demands from 2009¹⁵, 2010¹⁶ and 2011¹⁷ indicates that, on average, MISO LSEs under-forecast peak demand by approximately 1,000 MW; however, LFU analysis takes forecast error into account.

MISO derives an LFU value on an annual basis, from variance analysis to determine how likely actual load will deviate from forecasts. This assessment uses an LFU value of 4.42 percent from the 2012 LOLE Study report.¹⁸ LFU accounts for uncertainty in weather, economics and forecast error. The LFU is used to create a normal distribution around the 50/50 forecasts from Table 6.2-3 and low-load (10/90) and high-load (90/10) forecasts are determined. Details regarding this methodology are detailed in MISO's 2012 Summer Resource Assessment, Section 3.5. Table 6.2-4 provides 10/90 and 90/10 total internal demand forecasts, and provides book ends of the 10th-year peak total internal demand forecast ranging from 97,717 MW to 120,104 MW.

¹⁴ 2012 Summer Resource Assessment
¹⁵ Supply Adequacy Working Group (SAWG) 2010 meeting material
¹⁶ SAWG 2010 meeting material
¹⁷ Market Reports- PY2011-12 Module E Metrics
¹⁸ 2012 LOLE Study

| Level% | Total Internal Peak Demand, MW | 10-year Assessment Period | | | | | | | | | |
|--------|--------------------------------|---------------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| 4.61 | Module E 10/90 (BAU) | 88,939 | 90,684 | 91,439 | 92,270 | 93,136 | 93,968 | 94,868 | 95,779 | 96,749 | 97,717 |
| 4.61 | 10/90 (High Growth) | 90,375 | 91,835 | 93,318 | 94,825 | 96,357 | 97,913 | 99,494 | 101,101 | 102,734 | 104,393 |
| 2.02 | Module E 10/90 (BAU) | 91,354 | 93,146 | 93,921 | 94,776 | 95,665 | 96,520 | 97,444 | 98,379 | 99,376 | 100,370 |
| 2.02 | 10/90 (High Growth) | 92,829 | 94,328 | 95,852 | 97,400 | 98,973 | 100,571 | 102,196 | 103,846 | 105,523 | 107,227 |
| 4.61 | Module E 90/10 (BAU) | 99,620 | 101,574 | 102,420 | 103,351 | 104,321 | 105,253 | 106,261 | 107,281 | 108,368 | 109,452 |
| 4.61 | 90/10 (High Growth) | 101,229 | 102,864 | 104,525 | 106,213 | 107,928 | 109,671 | 111,442 | 113,242 | 115,071 | 116,930 |
| 2.02 | Module E 90/10 (BAU) | 102,325 | 104,332 | 105,200 | 106,157 | 107,154 | 108,111 | 109,146 | 110,194 | 111,311 | 112,424 |
| 2.02 | 90/10 (High Growth) | 103,977 | 105,657 | 107,363 | 109,097 | 110,859 | 112,649 | 114,468 | 116,317 | 118,196 | 120,104 |

Table 6.2-4: 2013-2022 Coincident 10/90 & 90/10 Demand Forecasts

Forecasted Capacity

MISO expects to see a 10th-year peak total available capacity between 110 GW and 122 GW depending on the impact of Attachment Y retirements and suspensions, the impact of the EPA regulations on future retirements, and the level of projects in MISO's generator interconnection queue built in the next 10 years. Table 6.2-5 provides the cumulative total available capacity projections throughout the 10-year assessment period.

The 10th-year peak total available capacity forecast utilizing 9,912 MW of EPA retirements and 2,710 MW of new generation is 109,770 MW

| Capacity, MW | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|-------------------------------------|---------------|---------------|------------------------|------------------------|---------------|------------------------|---------------|---------------|---------------|---------------|
| 2012 Internal Summer Rated Capacity | 112,679 | 112,679 | 112,679 | 112,679 | 112,679 | 112,679 | 112,679 | 112,679 | 112,679 | 112,679 |
| 2012 External Support (+) | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 | 3557 |
| Attachment-Y Retirements (-) | 363 | 363 | 363 | 363 | 363 | 363 | 363 | 363 | 363 | 363 |
| Attachment-Y In-Service (+) | 183 | 342 | 1,099 | 1,099 | 1,099 | 1,099 | 1,099 | 1,099 | 1,099 | 1,099 |
| EPA Retirement Range (-) | 0 - 0 | 0 - 0 | 9912 - 2341 | 9912 - 2341 | 9912 - 2341 | 9912 - 2341 | 9912 - 2341 | 9912 - 2341 | 9912 - 2341 | 9912 - 2341 |
| GIQ Range (+) | 129 - 1059 | 359 - 2319 | 669 - 3649 | 1123 - 5295 | 2686 - 6994 | 2710 - 7407 | 2710 - 7407 | 2710 - 7407 | 2710 - 7407 | 2710 - 7407 |
| Total Available Capacity | 116185 | 116574 | 107729 - 118280 | 108183 - 119926 | 109746 | 109770 - 122038 | 109770 | 109770 | 109770 | 109770 |

Table 6.2-5: 2013-2022 Forecasted Capacity

MISO's internal capacity forecast is based upon the summer rated (on-peak) capacities of registered generation assets from the March 2012 commercial model. Currently, 112,679 MW of on-peak capacity exists within the MISO market footprint. Figure 6.2-2 provides a breakdown of this capacity by resource type.

Summer rated capacity for non-intermittent resources is their generator verification test capacity (GVTC), and if a GVTC is not available, it is their registered maximum output from the commercial model. Details regarding non-intermittent GVTC requirements are documented in the Resource Adequacy BPM posted on MISO's webpage.

Summer rated capacity for wind resources is 14.7 percent of their total registered maximum output. Details regarding the 14.7 percent wind capacity credit are documented in the 2012 LOLE Study report posted on MISO's webpage. For all other intermittent resources, the summer rated capacity is their GVTC. Details regarding intermittent GVTC requirements are documented in the Resource Adequacy BPM posted on MISO's webpage.

MISO anticipates retirements due to the EPA regulations to take effect as early as 2015. MISO conducts quarterly surveys of asset owners' EPA compliance strategies. From the second quarter 2012 survey, 47 units totaling 4 GW of summer rated capacity have either retired or will definitely retire.

MISO Summer Rated Capacity, MW

(112,679 MW)

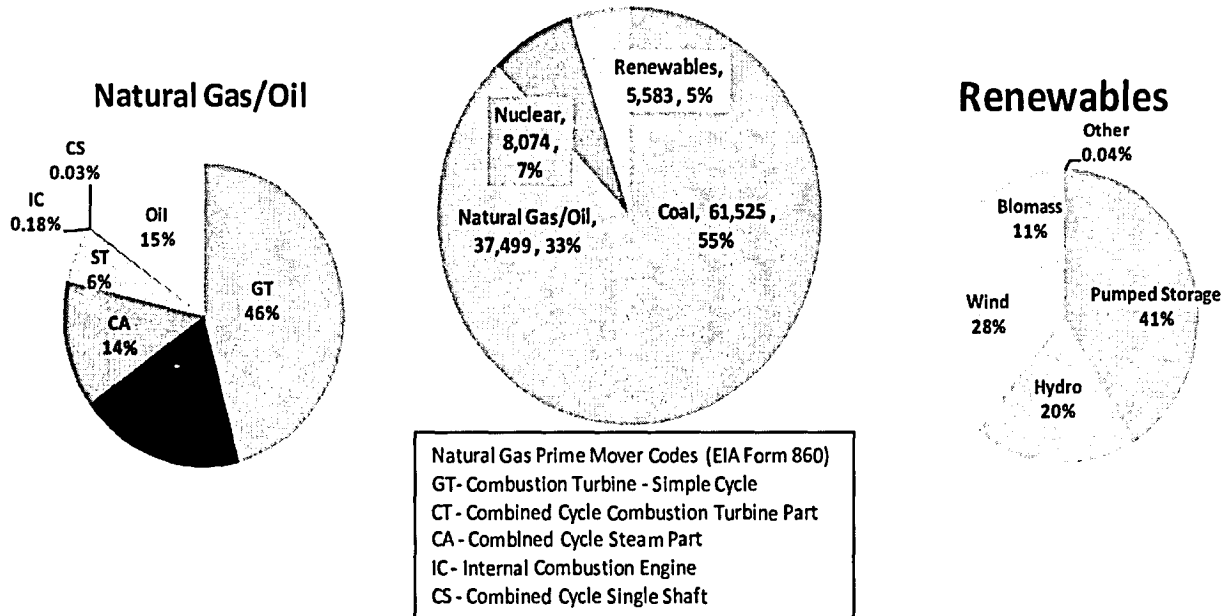


Figure 6.2-2: MISO 2012 Internal Summer Rated Capacity

Before the 2013 summer season, MISO expects 189 MW of GT natural gas units, 160 MW of coal units, and 14 MW of oil units, totaling 363 MW of 2012 summer rated capacity, to retire. These retirements have been approved through Attachment Y of MISO's Tariff.

Prior to the 2015 summer season, MISO expects 444 MW of coal units, 243 MW of GT natural gas units, 229 MW of oil units, and 183 MW of ST natural gas units, totaling 1,099 MW of summer rated capacity, to come back into service from Attachment Y suspensions.

In addition to Attachment Y impacts, MISO anticipates retirements due to the EPA regulations to take effect as early as 2015. MISO conducts quarterly surveys of asset owners' EPA compliance strategies. From the second quarter 2012 survey, 47 units totaling 4 GW of summer rated capacity have either retired or will definitely retire. 1,706 MW of coal has retired prior to March 2012. An additional 1,980 MW of coal units, 314 MW of combined cycle steam (CA) natural gas units utilizing coal as a secondary source of energy, and 47 MW of biomass units, totaling 2,341 MW of summer rated capacity, will definitely retire due to EPA regulations.

Also, from the second-quarter survey, an additional 73 units totaling 8 GW of summer rated capacity have yet to determine if they will retire in order to comply with the EPA regulations. This includes 7,197 MW of coal units, 295 MW of GT natural gas units utilizing coal as a secondary source or energy, and 79 MW of oil units; totaling 7,571 MW of summer rated capacity, which may retire due to EPA regulations.

For the purposes of this assessment, MISO utilizes the in-service dates and the maximum summer output from the generator interconnection queue (GIQ) to determine when and how much new capacity will come into service over the next 10 years. The wind capacity credit of 14.7 percent is applied to wind units maximum summer output. As of March 2012, MISO has 83 projects totaling 15,370 MW of summer rated capacity in the queue with an in-service year after or equal to 2013. Figure 6.2-3 provides the cumulative capacity by fuel type of all 83 projects in the queue regardless of study status or overall project status.

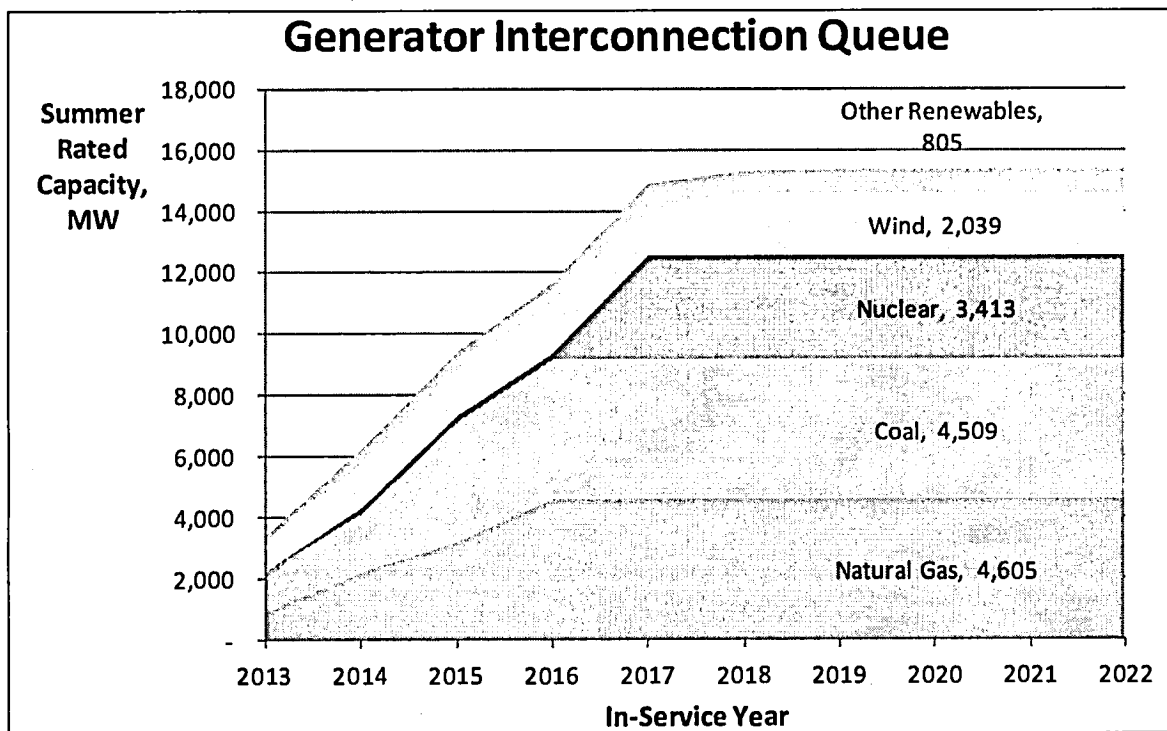


Figure 6.2-3: MISO GIQ Projects

Of the 15,370 MW of summer rated capacity in the queue, MISO expects a range of 2,709 MW to 7,407 MW to be built in the next 10 years. MISO developed this range utilizing confidence factors based on queue study statuses, fuel types, known regulatory approvals, contracts, firm transmission service requests, and other factors.

Forecasted Emergency Operating Procedure (EOP) Resources

MISO expects to see 10th-year peak available EOP resources between 5 GW and 12 GW depending on the growth of DR in MISO's footprint over the next 10 years. Table 6.2-6 provides the cumulative total available EOP resource projections throughout the 10-year assessment period.

| EOP Type | Total Emergency Operating Procedure (EOP) Resources - MW Range | | | | | | | | | |
|------------------------------------|--|-------------------------------|-------------------------------|-------------------------------|-------------------------------|--------------------------------|--------------------------------|--------------------------------|--------------------------------|--------------------------------|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Demand Response (DR) | 4,606 to 4,962 | 4,606 to 5,422 | 4,606 to 5,833 | 4,606 to 6,255 | 4,606 to 6,707 | 4,606 to 7,164 | 4,606 to 7,633 | 4,606 to 8,111 | 4,606 to 8,602 | 4,606 to 8,709 |
| Behind the Meter Generation (BTMG) | 3,271 | 3,271 | 3,271 | 3,271 | 3,271 | 3,271 | 3,271 | 3,271 | 3,271 | 3,271 |
| Total EOP | 7,877 to 8,233 | 7,877 to 8,693 | 7,877 to 9,104 | 7,877 to 9,526 | 7,877 to 9,978 | 7,877 to 10,435 | 7,877 to 10,904 | 7,877 to 11,382 | 7,877 to 11,873 | 7,877 to 11,980 |

Table 6.2-6: 2013-2022 Forecasted Operating Procedure Resources

MISO has procedures in place to provide instructions to Local Balancing Authorities (LBA), Transmission Operators (TOP), Generation Operators (GO), and Market Participants (MP) to manage capacity or energy emergencies. These emergency operating procedures are documented in the RTO-EOP-002 MISO Market Capacity Emergency Procedure document posted on MISO's webpage.^[1]

MISO's total available capacity projections include all resources up through a Maximum Generation Emergency Event Level 1c. Through that point MISO exhausts all emergency maximum limits of its committed generation units, all external support and outage coordination strategies.

For the purposes of this assessment, MISO forecasts emergency operating procedure resources starting at the Maximum Generation Emergency Event Level 2b, where MISO instructs the use of Module E Load Modifying Resources (LMR). Details regarding Module E LMR are documented in section 4.9 of the Resource Adequacy BPM.

MISO categorizes LMR into two categories, which are Demand Response (DR) and Behind the Meter Generation (BTMG). DR is resource designated as Interruptible Load (IL) or Direct Control Load Management (DCLM), and it reduces load by its obligated MW amount. BTMG is a generation resource used to serve load behind the meter, meaning it is not included in MISO's dispatch instructions. BTMG is treated as a capacity resource, while DR is treated as a load reduction in this assessment.

The DR amount for the current year (2012) is equal to 4,606 MW, which is approximately 5 percent of 2012 load. MISO has integrated the 2010 Global Energy Partners' assessment results into this year's projections of DR resources.^[2] Global Energy Partners determined the DR percentage of baseline load for 2010 as 3.7 percent, 2015 as 5.4 percent and 2020 as 7.2 percent. MISO adjusted these percentages to make the current study year (2012) the baseline year. Table 6.2-6 provides the DR percentages for each year of the 10-year assessment.

^[1] RTO-EOP-002 MISO Market Capacity Emergency Procedure

^[2] Global Energy Partners, LLC

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| 5.45% | 5.79% | 6.13% | 6.47% | 6.83% | 7.19% | 7.55% | 7.91% | 8.27% | 8.27% |

Table 6.2-6: Percent DR of Module E 50/50 Non-Coincident Demand

The BTMG amount for the current year (2012) is equal to 3,271 MW and is held flat throughout the 10-year assessment.

Gas and Electric Interdependencies and Potential Impact on Reserves

Given the magnitude of future coal unit retirements due to the EPA regulations, MISO will have to utilize natural gas fired generators more intensively to serve load. This prompted MISO to work with the natural gas industry to report on potential pipeline supply issues. This report is posted on MISO's webpage.

Using the pipeline flow data behind the analysis along with historical energy usage of existing natural gas fleet, MISO is currently in the process of performing loss of load expectation (LOLE) analysis in order to determine the impact of EPA retirements on LOLE. The analysis will model "what if" scenarios related to likely gas pipeline contingencies and their impact on electric generating unit availabilities.

EXHIBIT TFC-5

2013/2014 MISO Planning Resource Auction Results:

| Local Resource Zone (LRZ) | Z1 (MN, ND, Western WI) | Z2 (Eastern WI, Upper MI) | Z3 (IA) | Z4 (IL) | Z5 (MO) | Z6 (IN, KY) | Z7 (MI) | System |
|---|-------------------------------|---------------------------------|------------|------------|------------|----------------|------------|-----------|
| Planning Reserve Margin Requirements (PRMR) | 17,693.4 | 13,362.9 | 9,343.1 | 10,733.9 | 9,000.2 | 19,320.3 | 22,702.3 | 102,156.1 |
| Netted DR/EER* | 1197.1 | 728.7 | 528.8 | 112.3 | 0 | 1191.7 | 781.6 | 4,540.2 |
| Adjusted PRMR | 16,387.3 | 12,573.2 | 8,767.6 | 10,612.1 | 9,000.2 | 18,023.3 | 21,850.3 | 97,214.0 |
| Offer | | | | | | | | 70,412.1 |
| FRAP ¹ | | | | | | | | 34,959.3 |
| Offer + FRAP ¹ | | | | | | | | 105,371.4 |
| Offer Cleared + FRAP ¹ | | | | | | | | 97,214.0 |
| Local Clearing Requirement (LCR) | 15,707.7 | 10,326.2 | 6,796.4 | 5,231.9 | 5,490.7 | 14,283.5 | 21,055.0 | N/A |
| Capacity Import Limit (CIL) | 4,085.0 | 4,144.0 | 3,717.0 | 6,614.0 | 5,035.0 | 6,838.0 | 4,576.0 | N/A |
| Capacity Export Limit (CEL) | 1,416.0 | 1,766.0 | 1,612.0 | 2,230.0 | 1,616.0 | 3,432.0 | 4,306.0 | N/A |
| Auction Clearing Price (\$/MW-Day) | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | |

* Planning Reserve Margin and Transmission losses are not applied to Netted Demand Response (DR) and Energy Efficiency Resources (EERs) in the PRMR calculation.

¹ FRAP = Fixed Resource Adequacy Plan

EXHIBIT TFC-6



2016/2017 RPM Base Residual Auction Results

Executive Summary

The 2016/2017 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 169,159.7 MW of unforced capacity in the RTO. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR) the reserve margin for the entire RTO for the 2016/2017 Delivery Year is projected to be 21.1%, or 5.5% higher than the target reserve margin.

The 2016/2017 RPM BRA is the first auction to include the East Kentucky Power Cooperative (EKPC) load and resources that will be integrated into PJM on June 1, 2013. Absent the integration of the EKPC load, the forecast peak load for the 2016/2017 Delivery Year is effectively unchanged from 2015/2016. The 2016/2017 RPM BRA was also the first RPM auction for which the revised gross CONE values agreed to at settlement in ER12-513 were used and the revised Minimum Offer Price Rule (MOPR) filed by PJM on December 1, 2012, and accepted by FERC on May 3, 2013 was in effect.

This RPM auction included record setting combination of new generation, uprates, imports and energy efficiency surpassing the records in the 2015/2016 BRA. However, this BRA experienced a decrease in Demand Resource capacity offered and cleared.

Megawatts of Unforced Capacity Procured by Type

| BRA Delivery Year | New Generation | Generation Uprates | Imports | Demand Response | Energy Efficiency |
|-------------------|----------------|--------------------|---------|-----------------|-------------------|
| 2016/2017 | 4,281.6 | 1,181.3 | 7,482.7 | 12,408.1 | 1,117.3 |
| 2015/2016 | 4,898.9 | 447.4 | 3,935.3 | 14,832.8 | 922.5 |
| 2014/2015 | 415.5 | 341.1 | 3,016.5 | 14,118.4 | 822.1 |

The net increase in supply from new entry and imports in conjunction with what is effectively flat demand growth resulted in capacity prices that were lower across the PJM footprint except in parts of New Jersey. The RTO price for Annual Resources was \$59.37 per megawatt-day (MW-day). Prices for Limited Demand Resources (Limited DR) and Extended Summer Demand Resources (ES DR) mirrored the Annual Resource price at \$59.37/MW-day.

Transmission constraints resulted in higher capacity prices in the MAAC, ATSI, and PSEG Locational Deliverability Areas (LDA). The MAAC prices were \$119.13/MW-day for Annual, ES DR, and Limited DR products, prices in PSEG were \$219/MW-day for all resource products, and in ATSI Annual and ES DR product prices were \$114.23/MW-day while Limited DR cleared at \$94.45/MW-day signifying that Extended Summer minimum resource requirement was binding.



2016/2017 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2016/2017 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2016/2017 BRA opened on May 13, 2013 and the results were posted on May 24, 2013.

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing locational constraints and minimum requirements on the commitment of less limited capacity products. Locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA. A Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement is established for the RTO and each modeled LDA and the auction clearing process can select Extended Summer Demand Resources (DR) or Annual Resources (Annual Resources include generation capacity resources, energy efficiency resources and Annual DR) out of merit order, if necessary, to procure the minimum required quantities, similar to the way in which RPM auctions can select resources out of merit order to address locational constraints. In those cases where one or both of the minimum resource requirements do bind in the auction solution, just as with resources selected to resolve locational constraints, resources selected out of merit order to meet the necessary minimum resource requirements will receive a minimum resource requirement adder to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

This document begins with a high level summary of the BRA results followed by sections containing detailed descriptions of the 2016/2017 BRA results and a discussion of the results in the context of the nine previous BRAs.

Summary of Results

The 2016/2017 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 169,159.7 MW of unforced capacity in the RTO representing a 21.5% reserve margin. When the Fixed Resource Requirement (FRR) load and resources are considered the reserve margin for the entire RTO is 21.1%.

The auction results show a continuing trend, starting in the 2014/2015 BRA, of a significant decline in the amount of coal-fired generation cleared and a continued shift to increased amounts of new natural gas-fired generation cleared. The auction clearing prices are lower than the previous auction driven largely by a flat demand growth and an increase in supply from substantial amount of new entry offers, uprates associated with repowering existing resources to natural gas, increased imports, and withdrawn deactivations.

The MAAC LDA, PSEG LDA and ATSI LDA are locationally constrained in the 2016/2017 BRA; therefore, Resource Clearing Prices in these LDAs differ from the Resource Clearing Prices of the rest of the RTO. The Resource Clearing Price for Limited DR,



2016/2017 RPM Base Residual Auction Results

Extended Summer DR and Annual Resources located in the RTO is \$59.37/MW-day for all three capacity product types. The Resource Clearing Price for Limited DR, Extended Summer DR and Annual Resources located in the MAAC LDA is \$119.13/MW-day for all three capacity product types. The Resource Clearing Price for Limited DR, Extended Summer DR and Annual Resources located in the PSEG LDA is \$219.00/MW-day for all three capacity product types. The Resource Clearing Prices for Limited DR, Extended Summer DR and Annual Resources located in the ATSI LDA are \$94.45/MW-day, \$114.23/MW-day and \$114.23/MW-day, respectively. The Minimum Extended Summer Resource Requirement was a binding constraint for the ATSI LDA and since both Annual Resources and Extended Summer DR may be used to satisfy this constraint, Annual Resources and Extended Summer DR received a higher Resource Clearing Price than did Limited DR in the ATSI LDA.

The annual resource clearing price in the MAAC region decreased from \$167.46/MW-day in the 2015/2016 Delivery Year to \$119.13/MW-day in the 2016/2017 Delivery Year; the annual resource clearing price in the PSEG LDA increased from \$167.46/MW-day in the 2015/2016 Delivery Year to \$219.00/MW-day in the 2016/2017 Delivery Year; the annual resource clearing price in the ATSI LDA decreased from \$357.00/MW-day in the 2015/2016 Delivery Year to \$114.23/MW-day in the 2016/2017 Delivery Year; and the annual resource clearing price in the rest of RTO region decreased from \$136.00/MW-day in the 2015/2016 Delivery Year to \$59.37/MW-day in the 2016/2017 Delivery Year.

The total quantity of new generation capacity resources offered into the auction was 6,597.9 MW (UCAP) comprised of 5,195.1 MW of new generation units and 1,402.8 MW of uprates to existing generation units. The quantity of new generation capacity resources cleared was 5,462.9 MW (UCAP) comprised of 4,281.6 MW (UCAP) from new generation units and 1,181.3 MW from uprates to existing generation units. The 5,462.9 MW of cleared from new generation capacity resources exceeds last year's then-record number of new generation capacity resources cleared in any single RPM auction of 5,346.3 MW.

The 2016/2017 Base Residual Auction results reflect a significant increase in the quantity of imports offered. The 7,493.7 MW (UCAP) of imports offered into the 2016/2017 BRA represents an increase of 3,558.4 MW (90.4%) over the imports that offered into the 2015/2016 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. The quantity of both offered and cleared imports from generation resources located in MISO (including areas that will be integrated into MISO by the 2016/2017 Delivery Year) totaled 4,723.1 MW (UCAP). To participate in RPM, an external resource must demonstrate that it has requested Firm Transmission Service from the resource to and into PJM. Of the 7,482.7 MW of the offered imports that cleared in the auction, 4,788 MW (64%) have firm transmission service from the resource into PJM that is in confirmed status and the remainder has submitted firm transmission service requests for the complete required path that are now under study.



2016/2017 RPM Base Residual Auction Results

14,507.2 MW (UCAP) of demand resources offered into the 2016/2017 BRA which represents a decrease of 5,449.1 MW (27.3%) from the demand resources that offered into the 2015/2016 BRA. Approximately 86% (12,408.1 MW) of these demand resources cleared in the auction. Demand resources totaling 501.9 MW were included in FRR capacity plans for total DR capacity market participation of 15,009.1 MW.

The total quantity of energy efficiency (EE) resources offered into the 2016/2017 BRA was 1,156.8 MW (UCAP) which represents an increase of 23% over the EE resources that offered into the 2015/2016 BRA. Approximately 97% (1,117.3 MW UCAP) of these EE resources cleared in the auction.

All existing generation sell offers into the 2016/2017 BRA were subject to market power mitigation through the application of the Market Structure Test (i.e., the Three-Pivotal Supplier Test). The RTO as a whole failed the Market Structure Test, resulting in mitigation of any existing generation resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved offer cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

All generation capacity resources (including uprates to existing resources units of 20 MW or greater) that are based on combustion turbine, combined cycle and integrated gasification combined cycle technologies that have not cleared an RPM Auction prior to February 1, 2013 are subject to the Minimum Offer Price Rule (MOPR). External generation capacity resources meeting the above criteria and that have entered commercial operation on or after January 1, 2013 and that require sufficient transmission investment for delivery into PJM are also subject to MOPR. To avoid application of the minimum offer price, Capacity Market Sellers may request exemption through either a Competitive Entry Exemption request or a Self-Supply Exemption request. The table below shows the requested, granted and cleared aggregate quantity (in ICAP MW) of each exemption type received and processed by PJM.

| Exemption Type | Requested Quantity (ICAP MW) | Granted Quantity (ICAP MW) | Cleared Quantity (ICAP MW) |
|-------------------|---------------------------------|-------------------------------|-------------------------------|
| Competitive Entry | 11,820.6 | 11,820.6 | 3,482.1 |
| Self-Supply | 1,432.5 | 1,432.5 | 1,432.5 |
| Total | 13,253.1 | 13,253.1 | 4,914.6 |



2016/2017 RPM Base Residual Auction Results

A further discussion of the 2016/2017 Base Residual Auction results and additional information regarding the 2016/2017 Reliability Pricing Model (RPM) Base Residual Auction results are detailed in the body of this report. The discussion also provides a comparison of the 2016/2017 auction results to the results from the 2007/2008 through 2015/2016 RPM auctions.



2016/2017 RPM Base Residual Auction Results

2016/2017 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices resulting from the 2016/2017 RPM Base Residual Auction in comparison to those from 2007/2008 through 2015/2016 RPM Base Residual Auctions.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

| Auction Results | RTO | | | | | | | | | |
|-------------------------|-----------|-----------|-----------|-----------|------------------------|-----------|------------------------|------------------------|------------------------|------------------------|
| | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 ¹ | 2012/2013 | 2013/2014 ² | 2014/2015 ³ | 2015/2016 ⁴ | 2016/2017 ⁵ |
| Resource Clearing Price | \$40.80 - | \$111.92 | \$102.04 | \$174.29 | \$110.00 | \$16.46 | \$27.73 | \$125.99 | \$136.00 | \$59.37 |
| Cleared UCAP (MW) | 129,409.2 | 129,597.6 | 132,231.8 | 132,190.4 | 132,221.5 | 136,143.5 | 152,743.3 | 149,974.7 | 164,561.2 | 169,159.7 |
| Reserve Margin | 19.2% | 17.5% | 17.8% | 16.5% | 18.1% | 20.9% | 20.2% | 19.6% | 20.2% | 21.1% |

1) 2011/2012 BRA was conducted without Duquesne zone load.

2) 2013/2014 BRA includes ATSI zone

3) 2014/2015 BRA includes Duke zone

4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative

5) 2016/2017 BRA includes EKPC zone

The cleared UCAP is the amount of unforced capacity that was procured in the auction to meet the RTO demand for capacity. The 2016/2017 Reliability Pricing Model (RPM) Base Residual Auction cleared 169,159.7 MW of unforced capacity in the RTO representing a 21.5% reserve margin. When the Fixed Resource Requirement (FRR) load and associated resources are considered the actual reserve margin for the entire RTO is 21.1%. The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative).

New Generation Resource Participation

The 2016/2017 Base Residual Auction results reflect a continuation of last year's strong participation by new generation capacity resources mostly in the form of new (or uprates to existing) gas-fired combustion turbine and combined cycle generation units. The total quantity of new generation capacity resources offered into the auction was 6,597.9 MW (UCAP) comprised of 5,195.1 MW of new generation units and 1,402.8 MW of uprates to existing generation units. The quantity of new generation capacity resources cleared was 5,462.9 MW (UCAP) comprised of 4,281.6 MW (UCAP) from new generation units and 1,181.3 MW from uprates to existing generation units. The 5,462.9 MW of cleared new generation capacity resources exceeds last year's then-record number of new generation capacity resources cleared in any single RPM auction of 5,346.3 MW.



2016/2017 RPM Base Residual Auction Results

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing units offered in the auction and capacity actually clearing in the auction. 83% of the new generation capacity that offered into the 2016/2017BRA cleared the auction.

Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)

| LDA | Offered | | | Cleared | | |
|------------------|----------------|----------------|----------------|----------------|----------------|----------------|
| | Uprate | New Unit | Total | Uprate | New Unit | Total |
| EMAAC | 578.6 | 215.5 | 794.1 | 383.0 | 59.0 | 442.0 |
| MAAC | 858.0 | 1,711.1 | 2,569.1 | 662.4 | 1,554.6 | 2,217.0 |
| Total RTO | 1,402.8 | 5,195.1 | 6,597.9 | 1,181.3 | 4,281.6 | 5,462.9 |

*All MW Values are in UCAP Terms

*MAAC includes EMAAC

**RTO includes MAAC

Capacity Import Participation

As shown in Table 2B, the 2016/2017 Base Residual Auction results reflect a significant increase in the quantity of imports offered. The imports offered into the 2016/2017 BRA was 7,493.7 MW (UCAP) which represents an increase of 3,558.4 MW (90.4%) over the imports that offered into the 2015/2016 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. The quantity of both offered and cleared imports from generation resources located in MISO (including areas that will be integrated into MISO by the 2016/2017 Delivery Year) were 4,723.1 MW (UCAP). To participate in RPM, an external resource must demonstrate that it has requested Firm Transmission Service from the resource to and into PJM. Of the 7,482.7 MW of imports that cleared in the auction, 4,788 MW (64%) has firm transmission service from the resource into PJM that is in confirmed status and the remainder has submitted firm transmission service requests for the complete required path that are now under study.

Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

| Region | Offered MW* | | | Cleared MW* | | |
|----------------------|----------------|----------------|----------------|----------------|----------------|----------------|
| | 2015/2016 | 2016/2017 | Delta | 2015/2016 | 2016/2017 | Delta |
| West of PJM | 3,621.2 | 7,080.5 | 3,459.3 | 3,621.2 | 7,069.5 | 3,448.3 |
| Other | 314.1 | 413.2 | 99.1 | 314.1 | 413.2 | 99.1 |
| Total Imports | 3,935.3 | 7,493.7 | 3,558.4 | 3,935.3 | 7,482.7 | 3,547.4 |

*All MW Values are in UCAP Terms



2016/2017 RPM Base Residual Auction Results

Demand Resource Participation

The total quantity of demand resources offered into the 2016/2017 BRA was 14,507.2 MW (UCAP), representing a decrease of 27.3% over the demand resources that offered into the 2015/2016 BRA. Of the 14,507.2 MW of total demand response that offered in this auction, 12,408.1 MW cleared and will be awarded capacity payments. The cleared demand response is 2,424.7 MW less than that which cleared in the 2015/2016 BRA representing a 16.3% decrease. Of this change, 1,298.5 fewer MWs of DR cleared in the MAAC LDA and 1,126.2 fewer MWs of DR cleared outside of the MAAC LDA. Table 3A contains a comparison of the Demand Resources Offered and Cleared in 2015/2016 BRA & 2016/2017 BRA represented in UCAP.



2016/2017 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2015/16 BRA & 2016/17 BRA represented in UCAP

| LDA | Zone | Offered MW* | | | Cleared MW* | | |
|-------------------------|---------|-----------------|-----------------|------------------------|-----------------|-----------------|------------------------|
| | | 2015/2016 | 2016/2017 | Increase in Offered MW | 2015/2016 | 2016/2017 | Increase in Cleared MW |
| EMAAC | AECO | 249.2 | 189.8 | (59.4) | 207.9 | 172.3 | (35.6) |
| EMAAC/DPL-S | DPL | 524.3 | 471.4 | (52.9) | 433.5 | 439.5 | 6.0 |
| EMAAC | JCPL | 524.0 | 252.0 | (272.0) | 350.2 | 222.7 | (127.5) |
| EMAAC | PECO | 1,458.1 | 592.9 | (865.2) | 801.8 | 531.1 | (270.7) |
| PSEG/PS-N | PSEG | 1,081.9 | 636.5 | (445.4) | 796.1 | 630.7 | (165.4) |
| EMAAC | RECO | 37.4 | 12.4 | (25.0) | 20.9 | 10.1 | (10.8) |
| EMAAC Sub Total | | 3,874.9 | 2,155.0 | (1,719.9) | 2,610.4 | 2,006.4 | (604.0) |
| PEPCO | PEPCO | 966.4 | 683.8 | (282.6) | 867.4 | 663.9 | (203.5) |
| SWMAAC | BGE | 1,328.8 | 970.0 | (358.8) | 1,141.7 | 936.6 | (205.1) |
| MAAC | METED | 472.2 | 407.6 | (64.6) | 348.6 | 313.6 | (35.0) |
| MAAC | PENELEC | 710.7 | 452.0 | (258.7) | 525.6 | 431.5 | (94.1) |
| MAAC | PPL | 1,810.3 | 1,035.1 | (775.2) | 1,155.0 | 998.2 | (156.8) |
| MAAC** Sub Total | | 9,163.3 | 5,703.5 | (3,459.8) | 6,648.7 | 5,350.2 | (1,298.5) |
| RTO | AEP | 2,175.6 | 1,720.6 | (455.0) | 1,684.4 | 1,377.2 | (307.2) |
| RTO | APS | 1,175.1 | 945.1 | (230.0) | 935.5 | 684.6 | (250.9) |
| ATSI | ATSI | 2,038.5 | 1,920.7 | (117.8) | 1,763.7 | 1,811.9 | 48.2 |
| RTO | COMED | 2,765.9 | 1,722.3 | (1,043.6) | 1,698.2 | 1,236.2 | (462.0) |
| RTO | DAY | 324.8 | 301.3 | (23.5) | 196.9 | 246.8 | 49.9 |
| RTO | DEOK | 358.8 | 394.9 | 36.1 | 278.9 | 304.4 | 25.5 |
| RTO | DOM | 1,653.1 | 1,457.5 | (195.6) | 1,381.8 | 1,120.6 | (261.2) |
| RTO | DUQ | 301.2 | 204.5 | (96.7) | 244.7 | 143.1 | (101.6) |
| RTO | EKPC | - | 136.8 | 136.8 | - | 133.1 | 133.1 |
| Grand Total | | 19,956.3 | 14,507.2 | (5,449.1) | 14,832.8 | 12,408.1 | (2,424.7) |

*All MW values are expressed in UCAP

**MAAC sub-total includes all MAAC Zones

Each demand resource (DR) offering into the 2016/2017 RPM BRA was identified by the DR provider as being one of three DR product types: (1) Annual DR, (2) Extended Summer DR or (3) Limited DR. A DR provider with a resource that can potentially qualify as more than one of the three DR product types may submit separate but coupled sell offers for each DR product type for



2016/2017 RPM Base Residual Auction Results

which it qualifies. By coupling separate DR offers, the seller informs PJM and the RPM auction clearing engine that only one of the coupled demand resources may clear at most. Submitting DR offers in a coupled manner is not a requirement; it is an optional offer type available to the seller in addition to the conventional, non-coupled offer type. DR offers that are not specified as being coupled offers are cleared independent of each other and each offer could potentially clear.

Table 3B shows a breakdown of Demand Resources Offered and Cleared in the 2016/2017 BRA grouped by the potential Demand Resource coupling scenarios.

Table 3B – Breakdown of Demand Resources Offered versus Cleared by Product Type in the 2016/17 BRA in UCAP

| Coupling Scenario | Resource Offer MW (UCAP) | | | Cleared MW (UCAP) | | |
|--------------------------------------|--------------------------|------------------------|------------------------|-------------------------|------------------------|------------------------|
| | Limited Product Type | Extended | | Limited Product Type | Extended | |
| | | Summer Product Type | Annual Product Type | | Summer Product Type | Annual Product Type |
| Annual, Extended Summer, and Limited | 3,020.5 | 2,984.0 | 2,952.1 | 1,788.8 | 342.6 | - |
| Annual and Extended Summer | - | 23.8 | 19.2 | - | 0.7 | - |
| Annual and Limited | - | - | - | - | - | - |
| Extended Summer and Limited | 4,603.3 | 4,603.4 | - | 3,393.3 | 333.2 | - |
| Annual Only | - | - | 114.6 | - | - | 88.6 |
| Extended Summer Only | - | 1,823.6 | - | - | 1,793.5 | - |
| Limited Only | 4,919.4 | - | - | 4,667.4 | - | - |
| Grand Total | 12,543.2 | 9,434.8 | 3,085.9 | 9,849.5 | 2,470.0 | 88.6 |

Energy Efficiency Resource Participation

An energy efficiency (EE) resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the delivery year, without any requirement of notice, dispatch, or operator intervention. Of the 1,156.8 MWs of energy efficiency that offered into the 2016/2017 Base Residual Auction, 1,117.3 MW of EE resources cleared in the auction and will be awarded capacity payments.



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Table 3C contains a summary of the demand resources and energy efficiency resources that offered and cleared by zone in the 2016/2017 Base Residual Auction. Approximately 85.5% of the demand resources and 96.6% of the energy efficiency resources that were offered into the BRA cleared. The uncleared resources were offered at a price above the applicable clearing price for the LDA in which the resource was offered.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2016/2017 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and demand resources offered into each BRA and nominated in FRR Plans, and energy efficiency resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1 total demand side participation has and cleared resources for the 2016/2017 BRA have fallen below the levels seen in the 2014/2015 BRA.



2016/2017 RPM Base Residual Auction Results

Table 3C – Comparison of Demand Resources and Energy Efficiency Resources Offered versus Cleared in the 2016/17

| LDA | Zone | Offered MW* | | | Cleared MW* | | |
|-------------------------|---------|-----------------|----------------|-----------------|-----------------|----------------|-----------------|
| | | Demand | EE | Total | Demand | EE | Total |
| EMAAC | AECO | 189.8 | 2.0 | 191.8 | 172.3 | 1.7 | 174.0 |
| EMAAC/DPL-S | DPL | 471.4 | 22.4 | 493.8 | 439.5 | 21.2 | 460.7 |
| EMAAC | JCPL | 252.0 | 10.2 | 262.2 | 222.7 | 4.9 | 227.6 |
| EMAAC | PECO | 592.9 | 14.6 | 607.5 | 531.1 | 11.5 | 542.6 |
| PSEG/PS-N | PSEG | 636.5 | 14.9 | 651.4 | 630.7 | 11.9 | 642.6 |
| EMAAC | RECO | 12.4 | - | 12.4 | 10.1 | - | 10.1 |
| EMAAC Sub Total | | 2,155.0 | 64.1 | 2,219.1 | 2,006.4 | 51.2 | 2,057.6 |
| PEPCO | PEPCO | 683.8 | 83.7 | 767.5 | 663.9 | 83.5 | 747.4 |
| SWMAAC | BGE | 970.0 | 124.9 | 1,094.9 | 936.6 | 124.9 | 1,061.5 |
| MAAC | METED | 407.6 | 11.1 | 418.7 | 313.6 | 10.4 | 324.0 |
| MAAC | PENELEC | 452.0 | 10.6 | 462.6 | 431.5 | 9.9 | 441.4 |
| MAAC | PPL | 1,035.1 | 36.5 | 1,071.6 | 998.2 | 30.2 | 1,028.4 |
| MAAC** Sub Total | | 5,703.5 | 330.9 | 6,034.4 | 5,350.2 | 310.1 | 5,660.3 |
| RTO | AEP | 1,720.6 | 118.9 | 1,839.5 | 1,377.2 | 118.7 | 1,495.9 |
| RTO | APS | 945.1 | 19.2 | 964.3 | 684.6 | 14.4 | 699.0 |
| ATSI | ATSI | 1,920.7 | 198.9 | 2,119.6 | 1,811.9 | 196.6 | 2,008.5 |
| RTO | COMED | 1,722.3 | 426.7 | 2,149.0 | 1,236.2 | 426.7 | 1,662.9 |
| RTO | DAY | 301.3 | 13.1 | 314.4 | 246.8 | 12.9 | 259.7 |
| RTO | DEOK | 394.9 | 5.7 | 400.6 | 304.4 | 5.2 | 309.6 |
| RTO | DOM | 1,457.5 | 30.2 | 1,487.7 | 1,120.6 | 28.4 | 1,149.0 |
| RTO | DUQ | 204.5 | 13.2 | 217.7 | 143.1 | 4.3 | 147.4 |
| RTO | EKPC | 136.8 | - | 136.8 | 133.1 | - | 133.1 |
| Grand Total | | 14,507.2 | 1,156.8 | 15,664.0 | 12,408.1 | 1,117.3 | 13,525.4 |

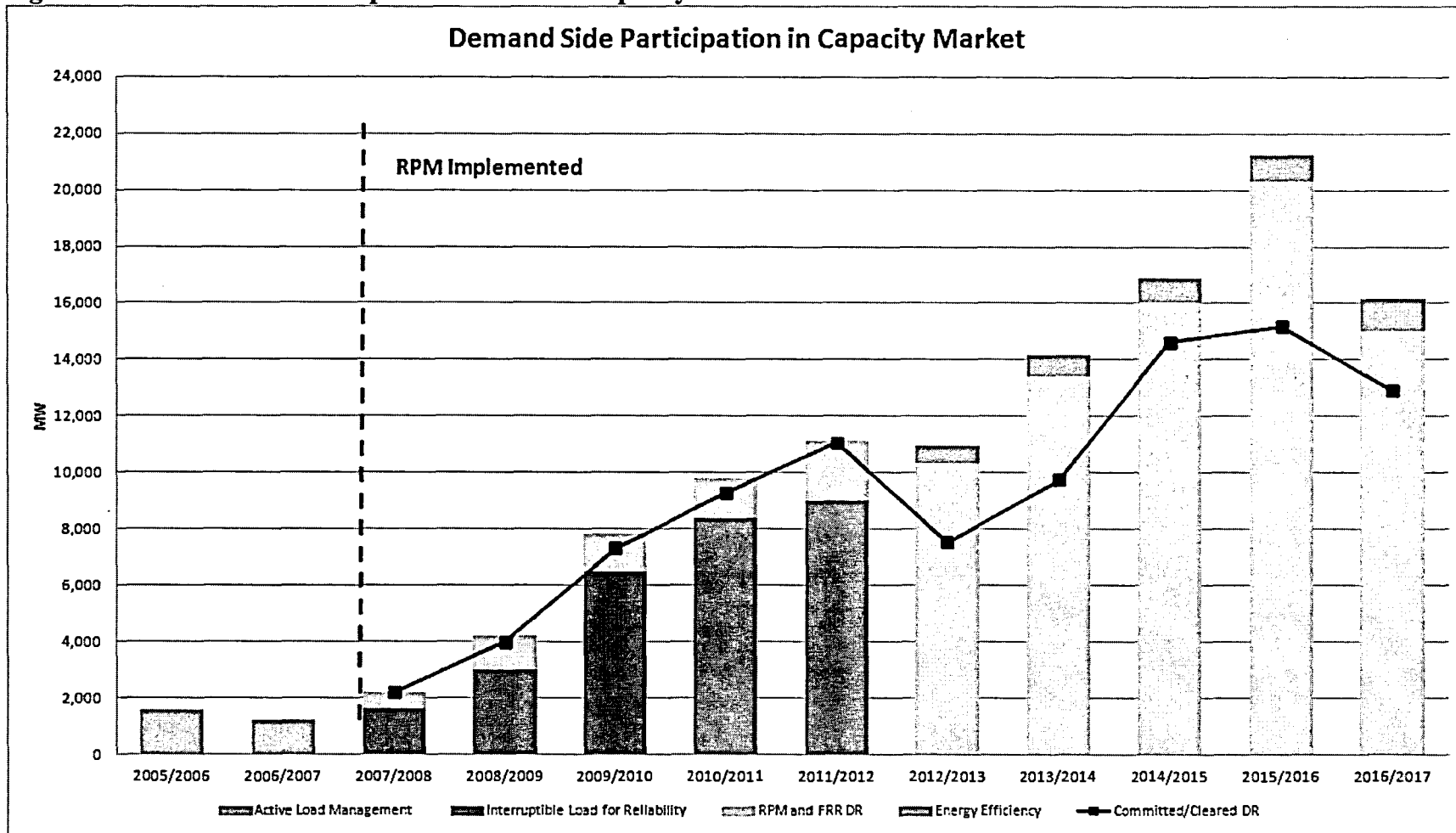
*All MW values are expressed in UCAP

**MAAC sub-total includes all MAAC Zones



2016/2017 RPM Base Residual Auction Results

Figure 1 – Demand Side Participation in the PJM Capacity Market





2016/2017 RPM Base Residual Auction Results

Renewable Resource Participation

870.5 MW of wind resources were offered into and cleared the 2016/2017 Base Residual Auction as compared to 796.3 MW of wind resources that offered into and cleared the 2015/2016 Base Residual Auction. The capacity factor applied to wind resources is 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements. The 870.5 MW of cleared wind capacity translates to 6,696 MW of wind energy nameplate capability that is expected to be available in the 2016/2017 Delivery Year.

89.8 MW of solar resources were offered into and cleared the 2016/2017 Base Residual Auction as compared to 56.2 MW of solar resources that offered into and cleared the 2015/2016 Base Residual Auction. The capacity factor applied to solar resources is 38%, meaning that for every 100 MW of solar energy, 38 MW are eligible to meet capacity requirements. The 89.8 MW of cleared solar capacity translates to 236.3 MW of solar energy that is expected to be available in the 2016/2017 Delivery Year.

LDA Results

An LDA was modeled in the Base Residual Auction and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding Base Residual Auctions; or (3) the LDA is likely to have a locational price adder based on a PJM analysis using historic offer price levels; or (4) the LDA is EMAAC, SWMAAC, and MAAC.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI and ATSI-Cleveland were modeled as LDAs in the 2016/2017 RPM Base Residual Auction; however, only the MAAC, PSEG and ATSI LDAs were binding constraints resulting in a Locational Price Adder for these LDAs. A Locational Price Adder represents the difference in Resource Clearing Prices for the Limited capacity product between a resource in a constrained LDA and the immediate higher level LDA.

Table 4 contains a summary of the clearing results in the LDAs from the 2016/2017 RPM Base Residual Auction.



2016/2017 RPM Base Residual Auction Results

Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

| Auction Results | RTO | MAAC | SWMAAC | PEPCO | EMAAC | DPL-SOUTH | PSEG | PS-NORTH | ATSI | ATSI-CLEVELAND |
|---|------------|-------------|---------------|--------------|--------------|------------------|-------------|-----------------|-------------|-----------------------|
| Offered MW (UCAP) | 184,380.0 | 71,607.5 | 12,385.0 | 6,126.1 | 34,139.9 | 1,764.4 | 6,784.3 | 4,181.6 | 12,791.3 | 2,874.3 |
| Cleared MW (UCAP) | 169,159.7 | 66,546.4 | 12,050.0 | 6,093.7 | 31,521.7 | 1,746.0 | 6,298.6 | 3,702.1 | 8,672.2 | 2,850.0 |
| System Marginal Price | \$59.37 | \$59.37 | \$59.37 | \$59.37 | \$59.37 | \$59.37 | \$59.37 | \$59.37 | \$59.37 | \$59.37 |
| Locational Price Adder* | \$0.00 | \$59.76 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$99.87 | \$0.00 | \$35.08 | \$0.00 |
| Extended Summer Price Adder** | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$19.78 | \$19.78 |
| Annual Price Adder | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 |
| Resource Clearing Price for Limited Resources | \$59.37 | \$119.13 | \$119.13 | \$119.13 | \$119.13 | \$119.13 | \$219.00 | \$219.00 | \$94.45 | \$94.45 |
| Resource Clearing Price for Extended Summer Resources | \$59.37 | \$119.13 | \$119.13 | \$119.13 | \$119.13 | \$119.13 | \$219.00 | \$219.00 | \$114.23 | \$114.23 |
| Resource Clearing Price for Annual Resources | \$59.37 | \$119.13 | \$119.13 | \$119.13 | \$119.13 | \$119.13 | \$219.00 | \$219.00 | \$114.23 | \$114.23 |

*Locational Price Adder is with respect to the immediate parent LDA

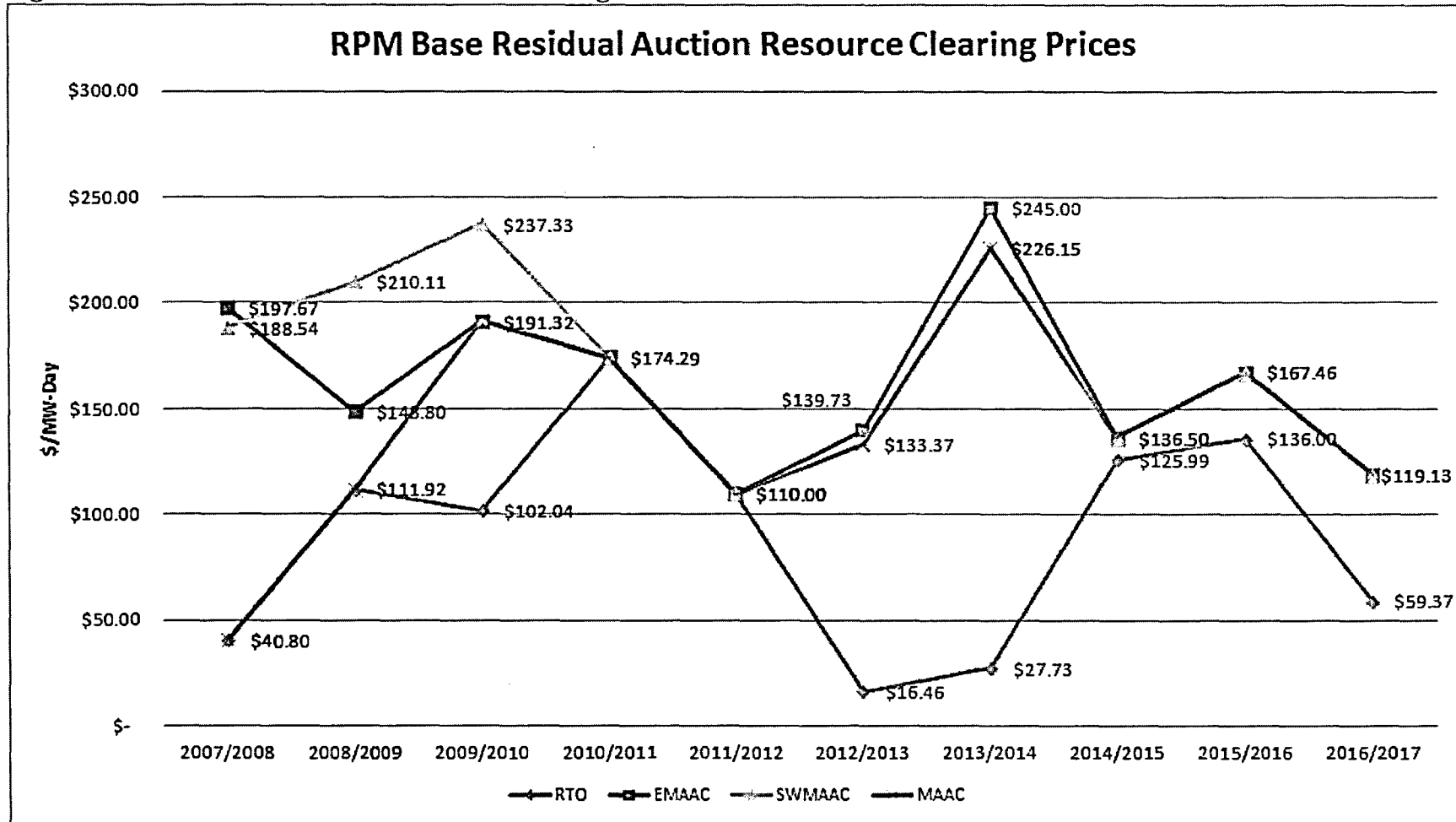
**Annual Resources and Extended Summer DR receive the Extended Summer Price Adder

Since the MAAC, PSEG and ATSI LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in the constrained LDAs for the 2016/2017 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.



2016/2017 RPM Base Residual Auction Results

Figure 2 – Base Residual Auction Resource Clearing Prices



*2014/2015 through 2016/2017 Prices reflect the Annual Resource Clearing Prices.



2016/2017 RPM Base Residual Auction Results

Table 5 contains a summary of the offer and resultant data in the RTO for each cleared Base Residual Auction from 2008/09 through the 2016/2017 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans)

A total of 216,510.2 MW of installed capacity was eligible to be offered into the 2016/2017 Base Residual Auction. Of this eligible amount, 8,412.2 MW were from external resources that had fulfilled the eligibility requirements to be considered a PJM Capacity Resource. As illustrated in Table 5, the amount of capacity exports in the 2016/2017 auction remained the same as that of the previous auction and FRR commitments decreased by 421.3 MW from the 2015/2016 Delivery Year to 15,576.6 MW.

A total of 191,190.8 MW of capacity was offered into the Base Residual Auction. This is an increase of 4,911.6 MW from that which was offered into the 2015/2016 BRA. A total of 25,319.4 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: environmental restrictions, approved retirement requests not yet reflected in eRPM, and excess capacity owned by an FRR entity.



2016/2017 RPM Base Residual Auction Results

Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

| Auction Supply (all values in ICAP) | RTO ¹ | | | | | | | | |
|--|------------------|------------------|------------------|------------------------|------------------|------------------------|------------------------|------------------------|------------------------|
| | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 ² | 2012/2013 | 2013/2014 ³ | 2014/2015 ⁴ | 2015/2016 ⁵ | 2016/2017 ⁶ |
| Internal PJM Capacity | 166,037.9 | 167,026.3 | 168,457.3 | 169,241.6 | 179,791.2 | 195,633.4 | 202,696.3 | 207,559.1 | 208,098.0 |
| Imports Offered | 2,512.0 | 2,563.2 | 2,982.4 | 6,814.2 | 4,152.4 | 4,766.1 | 4,299.4 | 4,649.7 | 8,412.2 |
| Total Eligible RPM Capacity | 168,649.9 | 169,589.5 | 171,439.7 | 176,055.8 | 183,943.6 | 200,399.5 | 206,995.7 | 212,208.8 | 216,510.2 |
| Exports / Delistings | 4,205.8 | 2,240.9 | 3,378.2 | 3,389.2 | 2,783.9 | 2,624.5 | 1,230.1 | 1,218.8 | 1,218.8 |
| FRR Commitments | 24,953.5 | 25,316.2 | 26,305.7 | 25,921.2 | 26,302.1 | 25,793.1 | 33,612.7 | 15,997.9 | 15,576.6 |
| Excused | 722.0 | 1,121.9 | 1,290.7 | 1,580.0 | 1,732.2 | 1,825.7 | 3,255.2 | 8,712.9 | 8,524.0 |
| Total Eligible RPM Capacity – Excused | 29,881.3 | 28,679.0 | 30,974.6 | 30,890.4 | 30,818.2 | 30,243.3 | 38,098.0 | 25,929.6 | 25,319.4 |
| Remaining Eligible RPM Capacity | 138,768.6 | 140,910.5 | 140,465.1 | 145,165.4 | 153,125.4 | 170,156.2 | 168,897.7 | 186,279.2 | 191,190.8 |
| Generation Offered | 138,076.7 | 140,003.6 | 139,529.5 | 143,568.1 | 142,957.7 | 156,894.1 | 153,048.1 | 166,127.8 | 176,145.3 |
| DR Offered | 691.9 | 906.9 | 935.6 | 1,597.3 | 9,535.4 | 12,528.7 | 15,043.1 | 19,243.6 | 13,932.9 |
| EE Offered | 0.0 | 0.0 | 0.0 | 0.0 | 632.3 | 733.4 | 806.5 | 907.8 | 1,112.6 |
| Total Eligible RPM Capacity Offered | 138,768.6 | 140,910.5 | 140,465.1 | 145,165.4 | 153,125.4 | 170,156.2 | 168,897.7 | 186,279.2 | 191,190.8 |
| Total Eligible RPM Capacity Unoffered | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

¹RTO numbers include all LDAs and include capacity of FRR Entities.

²All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.

³2013/2014 includes ATSI zone

⁴2014/2015 includes Duke zone

⁵2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative

⁶2016/2017 includes EKPC zone



2016/2017 RPM Base Residual Auction Results

Table 6 shows the Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORD values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. Demand resource (DR) sell offers and energy efficiency resource (EE) sell offers were converted into UCAP using the appropriate Demand Resource (DR) Factor and Forecast Pool Requirement (FPR) for the delivery year.

In UCAP terms, a total of 184,380.0 MW were offered into the 2016/2017 Base Residual Auction, comprised of 168,716.0 MW of generation capacity, 14,507.2 MW of capacity from demand resources, and 1,156.8 MW of capacity from energy efficiency resources. Of those offered, a total of 169,159.7 MW of capacity was cleared in the auction.

Of the 169,159.7 MW of capacity that cleared in the auction, 155,634.3 MW were from generation capacity, 12,408.1 MW were from demand resources, and 1,117.3 MW were from energy efficiency resources. Capacity that was offered but not cleared in the Base Residual Auction will be eligible to offer into the First, Second and Third Incremental Auctions for the 2016/2017 Delivery Year.

Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

| Auction Results (all values in UCAP ^{**}) | RTO [*] | | | | | | | | |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 |
| Generation Offered | 131,164.8 | 132,614.2 | 132,124.8 | 136,067.9 | 134,873.0 | 147,188.6 | 144,108.8 | 157,691.1 | 168,716.0 |
| DR Offered | 715.8 | 936.8 | 967.9 | 1,652.4 | 9,847.6 | 12,952.7 | 15,545.6 | 19,956.3 | 14,507.2 |
| EE Offered | - | - | - | - | 652.7 | 756.8 | 831.9 | 940.3 | 1,156.8 |
| Total Offered | 131,880.6 | 133,551.0 | 133,092.7 | 137,720.3 | 145,373.3 | 160,898.1 | 160,486.3 | 178,587.7 | 184,380.0 |
| Generation Cleared | 129,061.4 | 131,338.9 | 131,251.5 | 130,856.6 | 128,527.4 | 142,782.0 | 135,034.2 | 148,805.9 | 155,634.3 |
| DR Cleared | 536.2 | 892.9 | 939.0 | 1,364.9 | 7,047.2 | 9,281.9 | 14,118.4 | 14,832.8 | 12,408.1 |
| EE Cleared | 0.0 | 0.0 | 0.0 | 0.0 | 568.9 | 679.4 | 822.1 | 922.5 | 1,117.3 |
| Total Cleared | 129,597.6 | 132,231.8 | 132,190.5 | 132,221.5 | 136,143.5 | 152,743.3 | 149,974.7 | 164,561.2 | 169,159.7 |
| Uncleared | 2,283.0 | 1,319.2 | 902.2 | 5,498.8 | 9,229.8 | 8,154.8 | 10,511.6 | 14,026.5 | 15,220.3 |

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORD for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.



2016/2017 RPM Base Residual Auction Results

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 Base Residual Auction to the 2016/2017 Base Residual Auction. A total of 7,010.8 MW of incrementally new capacity in PJM was available for the 2016/2017 Base Residual Auction. This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources and new energy efficiency resources. The increase is more than offset by generation capacity deratings on existing generation capacity resources and a reduction in the quantity of offered demand resources to yield a net decrease of 3,291.9 MW of installed capacity.

Table 7 also illustrates the total amount of resource additions and reductions over ten Delivery Years since the implementation of the RPM construct. Over the period covering the first ten RPM Base Residual Auctions, 28,177.8 MW of new generation capacity was added which was partially offset by 20,319.4 MW of capacity de-ratings or retirements over the same period. Additionally, 14,370.7 MW of new demand resources and 1,112.6 MW of new energy efficiency resources were offered over the course of the ten Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last ten RPM auctions was 23,341.7 MW.

Table 7 – Incremental Capacity Resource Additions and Reductions to Date

| Capacity Changes (in ICAP) | RTO* | | | | | | | | | | Total |
|--|-----------|-----------|-----------|-----------|-----------|-----------|------------------------|------------------------|-----------|------------------------|-----------|
| | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 ¹ | 2014/2015 ² | 2015/2016 | 2016/2017 ³ | |
| Increase in Generation Capacity | 602.0 | 724.2 | 1,272.3 | 1,776.2 | 3,576.3 | 1,893.5 | 1,737.5 | 1,582.8 | 8,207.0 | 6,806.0 | 28,177.8 |
| Decrease in Generation Capacity | -674.6 | -375.4 | -550.2 | -301.8 | -264.7 | -3,253.9 | -1,924.1 | -1,550.1 | -6,432.6 | -4,992.0 | -20,319.4 |
| Net Increase in Demand Resource Capacity** | 555.0 | 574.7 | 215.0 | 28.7 | 661.7 | 7,938.1 | 2,993.3 | 2,514.4 | 4,200.5 | -5,310.7 | 14,370.7 |
| Net Increase in Energy Efficiency Capacity** | 0 | 0 | 0 | 0 | 0 | 632.3 | 101.1 | 73.1 | 101.3 | 204.8 | 1,112.6 |
| Net Increase in Installed Capacity | 482.4 | 923.5 | 937.1 | 1503.1 | 3973.3 | 7,210.0 | 2,907.8 | 2,620.2 | 6,076.2 | -3,291.9 | 23,341.7 |

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction.

- 1) Does not include Existing Generation located in ATSI Zone
- 2) Does not include Existing Generation located in Duke Zone
- 3) Does not include Existing Generation located in EKPC Zone



2016/2017 RPM Base Residual Auction Results

Table 7A provides a further breakdown of the generation increases and decreases for the 2016/2017 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2016/2017 Delivery Year

| LDA Name | Uprates | Derates |
|------------------|----------------|-----------------|
| EMAAC | 826.8 | -1,372.7 |
| MAAC | 2,667.9 | -2,762.8 |
| Total RTO | 6,806.0 | -4,992.0 |

All Values in ICAP terms

*MAAC includes EMAAC

**RTO includes MAAC

Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant quantity of generating capacity from new resources and uprates to existing resources offered into the 2016/2017 BRA. The capacity offered in the 2016/2017 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, coal, wind, and nuclear resources. While the largest growth remains in gas turbines and combined cycle plants, a fair amount of incremental capacity in Steam (coal) and Nuclear was offered into the recent auctions.

Figure 3 shows the continuing trend of increasing capacity commitments by natural gas-fired generation resources and decreasing commitments by coal-fired generation resources. Nearly 10,000 MW of coal that offered into the 2016/2017 Base Residual Auction did not clear the auction and cleared capacity from gas-fired generation resources exceeded cleared capacity from coal-fired generation resources by over 15,000 MW.



2016/2017 RPM Base Residual Auction Results

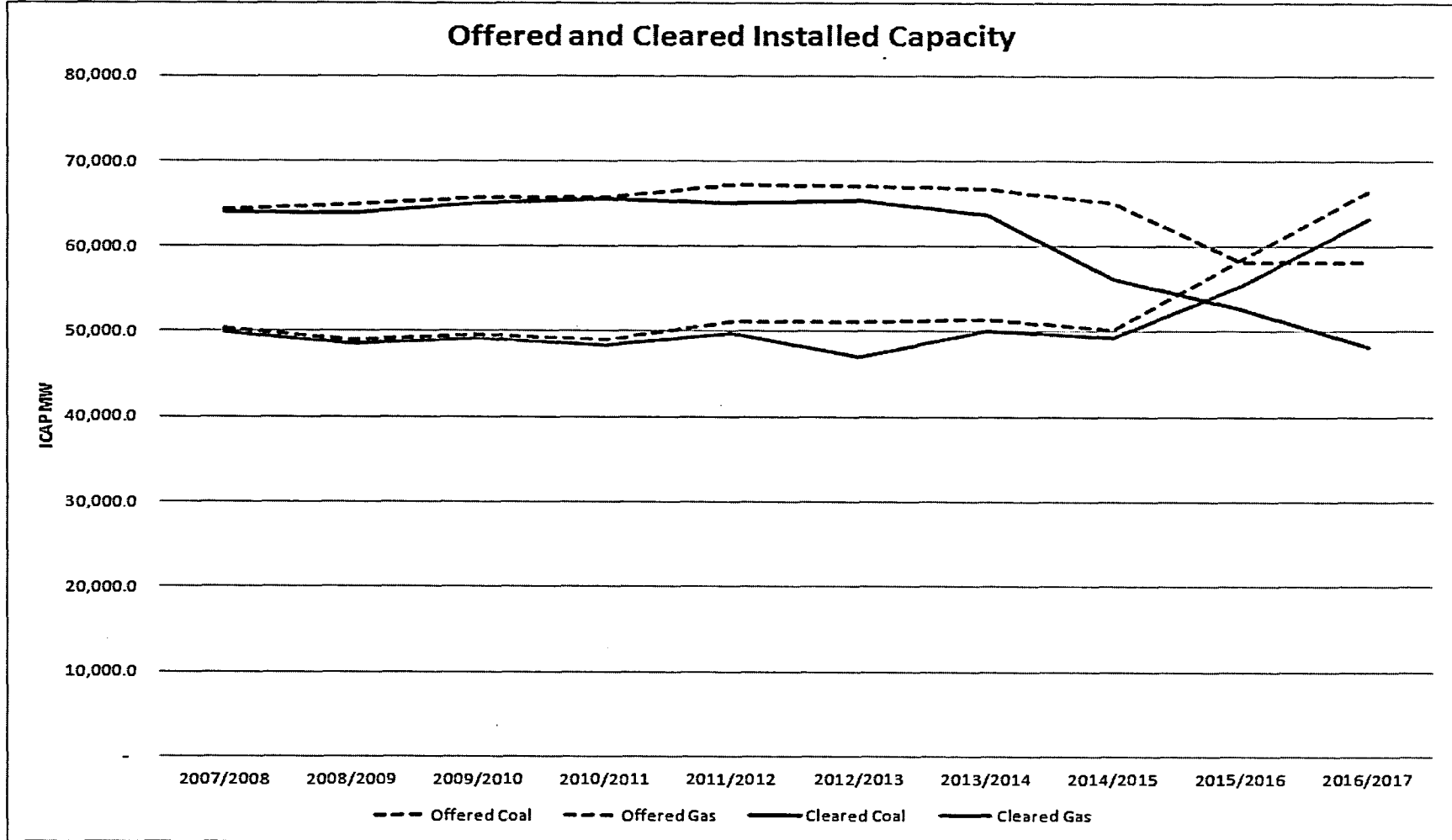
Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2016/17

| | Delivery Year | CT/GT | Combined Cycle | Diesel | Hydro | Steam | Nuclear | Solar | Wind | Fuel Cell | Total |
|--|----------------|-----------------|----------------|--------------|----------------|----------------|-------------|----------------|-------------|-----------------|---------|
| New Capacity Units (ICAP MW) | 2007/2008 | | | 18.7 | 0.3 | | | | | | 19.0 |
| | 2008/2009 | | | 27.0 | | | | | 66.1 | | 93.1 |
| | 2009/2010 | 399.5 | | 23.8 | | 53.0 | | | | | 476.3 |
| | 2010/2011 | 283.3 | 580.0 | 23.0 | | | | | 141.4 | | 1,027.7 |
| | 2011/2012 | 416.4 | 1,135.0 | | | 704.8 | | 1.1 | 75.2 | | 2,332.5 |
| | 2012/2013 | 403.8 | | 7.8 | | 621.3 | | | 75.1 | | 1,108.0 |
| | 2013/2014 | 329.0 | 705.0 | 6.0 | | 25.0 | | 9.5 | 245.7 | | 1,320.2 |
| | 2014/2015 | 108.0 | 650.0 | 35.1 | 132.9 | | | 28.0 | 146.6 | | 1,100.6 |
| | 2015/2016 | 1,382.5 | 5,914.5 | 19.4 | 148.4 | 45.4 | | 13.8 | 104.9 | 30.0 | 7,658.9 |
| | 2016/2017 | 171.1 | 4,994.5 | 38.3 | | 24.0 | | 32.1 | 54.3 | | 5,314.3 |
| Capacity from Reactivated Units (ICAP MW) | 2007/2008 | | | | | 47.0 | | | | | 47.0 |
| | 2008/2009 | | | | | 131.0 | | | | | 131.0 |
| | 2009/2010 | | | | | | | | | | - |
| | 2010/2011 | 160.0 | | 10.7 | | | | | | | 170.7 |
| | 2011/2012 | 80.0 | | | | 101.0 | | | | | 181.0 |
| | 2012/2013 | | | | | | | | | | - |
| | 2013/2014 | | | | | | | | | | - |
| | 2014/2015 | | | 9.0 | | | | | | | 9.0 |
| | 2015/2016 | | | | | | | | | | |
| | 2016/2017 | | | | | 21.0 | | | | | 21.0 |
| | 2007/2008 | 114.5 | | 13.9 | 80.0 | 235.6 | 92.0 | | | | 536.0 |
| | 2008/2009 | 108.2 | 34.0 | 18.0 | 105.5 | 196.0 | 38.4 | | | | 500.1 |
| | 2009/2010 | 152.2 | 206.0 | | 162.5 | 61.4 | 197.4 | | 16.5 | | 796.0 |
| | 2010/2011 | 117.3 | 163.0 | | 48.0 | 89.2 | 160.3 | | | | 577.8 |
| | 2011/2012 | 369.2 | 148.6 | 57.4 | | 186.8 | 292.1 | | 8.7 | | 1,062.8 |
| | 2012/2013 | 231.2 | 164.3 | 14.2 | | 193.0 | 126.0 | | 56.8 | | 785.5 |
| | 2013/2014 | 56.4 | 59.0 | 0.3 | | 215.0 | 47.0 | | 39.6 | | 417.3 |
| | 2014/2015 | 104.9 | | 0.5 | 41.5 | 138.6 | 107.0 | 7.1 | 73.6 | | 473.2 |
| | 2015/2016 | 216.8 | 72.0 | 4.7 | 15.7 | 63.4 | 149.2 | 2.2 | 24.1 | | 548.1 |
| | 2016/2017 | 436.6 | 420.0 | 3.3 | 7.4 | 484.3 | 102.6 | 1.7 | 14.8 | | 1,470.7 |
| Total | 5,640.9 | 15,245.9 | 331.1 | 742.2 | 3,636.8 | 1,312.0 | 95.5 | 1,143.4 | 30.0 | 28,177.8 | |



2016/2017 RPM Base Residual Auction Results

Figure 3 – Offered and Cleared Quantities of Coal and Gas

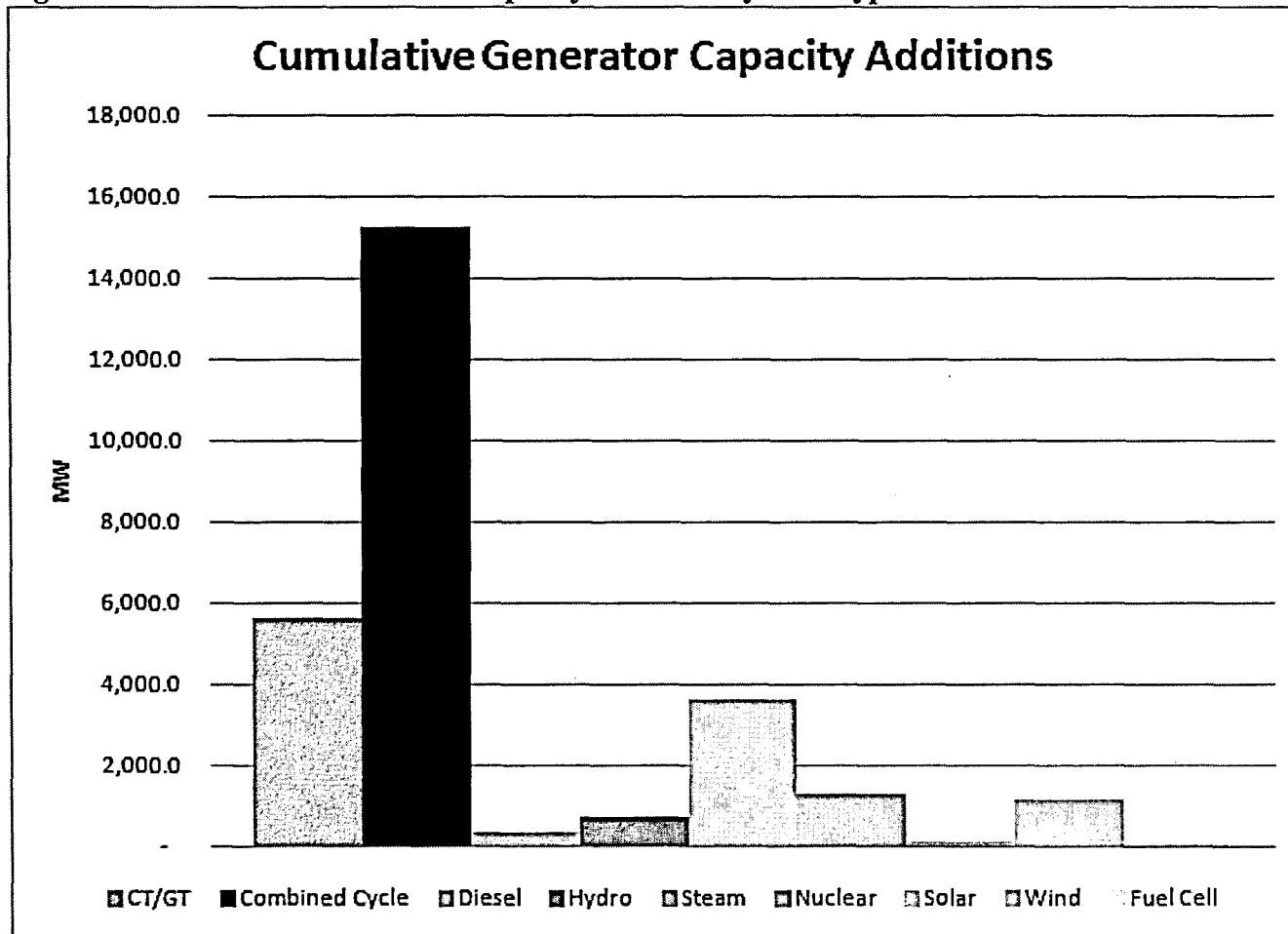




2016/2017 RPM Base Residual Auction Results

Figure 4 provides an illustration of the cumulative increase in new generation capacity by fuel type since the inception of RPM (June 1, 2007).

Figure 4: Cumulative Generation Capacity Increases by Fuel Type





2016/2017 RPM Base Residual Auction Results

Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2016/2017 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 4,422.6 MW of cleared UCAP in the 2016/2017 BRA which equates to 4,921.5 MW of ICAP Offered.

Table 9 – Changes to Generation Retirement Decisions since RPM

| Generation Resource Decision Changes | RTO | |
|--------------------------------------|----------------|----------------|
| | ICAP Offered | UCAP Cleared |
| Withdrawn Deactivation Requests | 2,272.6 | 1,875.4 |
| Postponed or Cancelled Retirement | 2,345.9 | 2,265.4 |
| Reactivation | 303.0 | 281.8 |
| Total | 4,921.5 | 4,422.6 |

RPM Impact To Date

As illustrated in Table 5, for the 2016/2017 auction, the capacity exports were 1218.8 MW and the capacity imports were 8,412.2 MW. The difference between the capacity imports and exports results is a net capacity import of 7,193.4 MW.

In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 7,193.4 MW. Therefore RPM's impact on PJM capacity interchange is 9,809.4 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2016/2017 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2016/2017 compared to what would have happened absent this implementation is 58,110.6 MW.



2016/2017 RPM Base Residual Auction Results

Table 10 shows the details on RPM's impact to date in ICAP terms.

Table 10 – RPM's Impact to Date

| Change in Capacity Availability | Installed Capacity MW |
|---|----------------------------------|
| New Generation | 20,450.6 |
| Generation Upgrades (not including reactivations) | 7,167.5 |
| Generation Reactivation | 559.7 |
| Forward Demand and Energy Efficiency Resources | 15,483.3 |
| Cleared ICAP from Withdrawn or Canceled Retirements | 4,640.1 |
| Net increase in Capacity Imports | 9,809.4 |
| Total Impact on Capacity Availability in 2016/2017 Delivery Year | 58,110.6 |



2016/2017 RPM Base Residual Auction Results

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2016/2017 RPM BRA clearing prices relative to 2015/2016 BRA clearing prices are provided below separated out by significant changes to the market design and effects on the demand-side and supply-side of the market. Overall, the main factors and events leading up to the 2016/2017 BRA were not as dramatic as the issuance of the final EPA Mercury and Air Toxics Standards and associated generation retirements, but are more incremental. Yet, there were sufficient incremental changes, many of which were not readily observable prior to the BRA, that reinforce one another such that taken together have resulted in the decrease in prices and higher reserve margin than resulted from the 2015/2016 BRA.

Significant Changes to RPM Design for the 2016/2017 Base Residual Auction

On January 31, 2013 in ER12-513 FERC approved updated gross Cost of New Entry (CONE) values that were filed as part of a settlement between PJM and various generation owners, load serving entities, industrial customers, and public power entities on November 21, 2012. The settlement CONE values resulted in gross CONE values that were slightly below the gross CONE values that would have been in place absent the settlement by 2.5 % in RTO, 0.5 % in MAAC, 1.4 % in PSEG, and 5.1 % in ATSI. As discussed below in the subsection regarding changes that affect demand, this slight reduction in gross CONE helped mitigate the Handy-Whitman Index adjustment to account for inflation used in developing 2016/2017 demand for capacity.

On May 3, 2013 FERC approved, with an effective date of February 5, 2013, changes to the Minimum Offer Price Rule (MOPR) filed on December 7, 2012 in ER13-535. The approved changes to the MOPR included the creation of Competitive Entry and Self Supply Exemptions for new entry, uprates to, and repowerings to combustion turbine, combined cycle, or IGCC technologies. All other technologies are exempt from the MOPR. In order to get a Competitive Entry Exemption a merchant plant developer can attest that it is receiving no anomalous revenue streams or subsidies that were not otherwise available to all market participants from state agencies or state procurement processes that had not been deemed competitive and non-discriminatory. A load serving entity could request a Self Supply Exemption by showing that it met specified net short and net long thresholds that indicated it had little or no incentive to exercise buyer side market power or inject excess ratepayer financed capacity into the market below cost as well as not receiving anomalous revenue streams or subsidies not generally available to other market participants from state agencies or procurement processes. Entities receiving the Competitive Entry or Self Supply Exemptions are permitted to offer their resources at any price they choose including a price of \$0/MW-day. The Commission also retained the unit specific exception process in place for the 2015/2016 BRA for resources that do not qualify for the Competitive Entry and Self Supply Exemptions. This change, while garnering much



2016/2017 RPM Base Residual Auction Results

attention likely had little effect on the BRA outcomes for 2016/2017 as less than half of all requested and approved MOPR exemptions were a part of the market clearing solution.

Finally, commencing in October 2012, PJM initiated a stakeholder process to address and implement enhancements to standardize the information that must be submitted as a part of Demand Resource (DR) Plans for approval prior to Planned DR being offered into the BRA. These enhancements were envisioned to be Manual changes only. The rationale for the enhancement and standardization of DR Plans came out of the observation that there was insufficient information in these plans that could be used by PJM in development of its Regional Transmission Expansion Plan (RTEP) and that offered DR in the 2015/2016 BRA exceeded 20 % of the forecast zonal peak load in some zones and may not reflect a practical level of DR penetration as CSPs may be counting the same resources/sites in each of their plans. On March 28, 2013 DR Plan enhancements were approved by the Markets and Reliability Committee. However, on April 3, 2013 a group of Curtailment Service Providers (CSPs) filed a complaint at the Commission in EL13-57 alleging the approved manual changes violated section 205 of the Federal Power Act in that they affect rates, terms and conditions of service and therefore should be filed with the Commission for approval. The Commission granted the complaint on April 19, 2013, the date DR Plans were due, such that the approved DR Plan Enhancements were not in effect for the 2016/2017 BRA. While not effective for the BRA, the discussion and stakeholder approval of the DR Plan Enhancements may have had the effect of causing CSPs to be more cautious about how much DR could reasonably be offered, and could explain the reduction in DR offered and cleared as discussed below.

Changes that impacted the Demand Curve:

- The forecast reliability requirement increased from 177,184.1 MW in 2015/2016 to 180,332.2 MW in 2016/2017 or an increase of 3,148.1 MW (1.77%). However, after accounting for the integration of the EKPC forecast peak load of 2,200.2 MW and adding the reserve margin of 15.6 %, the reliability requirement was effectively flat increasing only 604.7 MW (0.3%) and mostly attributed to the 0.2% increase in the installed reserve margin target rather than growing demand. Absent the EKPC load, the reliability requirement would still be below that used in the 2014/2015 BRA.
- The Net Cost of New Entry (CONE) values that serve as the basis for price on the RTO and LDA demand curves increased by 3.1% for the RTO, 3.5% in MAAC, 5.1% in EMAAC and PSEG, and 1.2% in ATSI. While the Handy-Whitman Index of Public Utility Construction Cost increased in the range of 8.9% to 9.4% from the 2015/2016 BRA, the overall increase in Net CONE was mitigated by small reduction in gross CONE values associated with the FERC-approved settlement values as



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discussed above and an increase in the Energy and Ancillary Service offset due to 2012 net revenues associated with lower gas prices replacing 2009 net revenues that had comparable LMPs but higher gas prices.^[1]

- Unlike the 2015/2016 BRA, there were no major shifts in load from or to Fixed Resource Requirement (FRR) plans. There was a small increase in the minimum resource requirements for Annual and Extended Summer resources as a result of FERC's approval of a new test used to establish the reliability targets for the Limited and Extended Summer DR products in docket ER13-486. There was no impact on the auction results as a result of the change in these targets since the new target values impacted only the RTO-wide and MAAC LDA values and the minimum resource requirements did not bind in the RTO or the MAAC LDA. The only change in demand is the inclusion of the EKPC coincident peak load forecast of 2,200 MW which is effectively offset by resources owned or controlled by EKPC that offset the increase in demand.
- The overall net impact of these year-over-year changes is to slightly increase the demand for capacity by shifting the Variable Resource Requirement (VRR) Curve up and to the right, but because the overall effect is relatively small, it was more than offset by the various factors affecting supply in the auction.

Changes that impacted the Supply Curve:

- Since the conclusion of the 2015/2016 BRA 2,710 MW have submitted deactivation notices which is significantly less than the announced retirements prior to the 2015/2016 BRA. Moreover, 1,346 MW of capacity have withdrawn their previous deactivation requests offsetting half of the deactivation requests in the past year. Overall, generator retirements have not had the same effect on reducing supply as was the case leading up to the previous two BRAs. On balance the net retirements had little effect on raising capacity prices. If the incremental retired capacity had not cleared the 2015/2016 BRA, then there would be no incremental effect on supply and market clearing in the 2016/2017 BRA. The withdrawn deactivations lead to increasing supply available to the market and thereby put downward pressure on capacity prices.
- The quantity of Demand Resources offered declined substantially by 5,449 MW UCAP or 27.3% from the DR resources offered last year. Accordingly, the quantity of Demand Resources clearing fell 2,425 MW UCAP or about 16.3%. The reduced pool of supply from Demand Resources, all else equal, places upward pressure on prices.

^[1] Refer to 2016/2017 RPM BRA Planning Period Parameters Report and the 2015/2016 RPM Planning Period Report



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- In contrast to the trend in Demand Response, Energy Efficiency Resources offered increased by 217 MW or 23% and cleared Energy Efficiency increased 195 MW or 21.1% offsetting a part of the decrease in Demand Resources.
- The 2016/2017 BRA attracted offers 6,597.9 MW of new generation capacity in the form of new facilities and uprates at existing facilities. This amounts to approximately one-half of the capacity that requested, and granted, Competitive Entry and Self-Supply Exemptions. While this new entry figure is about 724 MW less than last year, this deepened pool of supply has the effect of putting downward pressure on clearing prices. Furthermore, unlike the previous version of the MOPR in place for the 2015/2016 BRA, new entry with Competitive Entry and Self Supply Exemptions were not subject to an offer floor that existed under the unit specific exception process which could allow these new entrants to offer at lower prices than last year and possibly accentuate downward price pressures.
- On an unforced capacity (UCAP) basis offered imports increased 90% or 3,558 MW from 3,935 MW to 7,493 MW and the quantity of imports that cleared increased 3,547 MW or 90% to 7,482 MW. The quantity of imports offered and clearing is the highest ever for a BRA and clearly has the effect of increasing supply and placing downward pressure on capacity prices.
- The Avoidable Cost Rate (ACR) default values used a Handy-Whitman indexing method such that the 2016/2017 Delivery Year default ACR data was increased based on the ten-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Costs. The default ACR values are the default offer caps that suppliers may elect to use in the event the Market Structure Test is failed and the supplier chooses not to calculate a unit-specific ACR data. The offer caps are calculated as the ACR less net revenues. Participants may choose either the technology specific default rate or to calculate their own based on unit-specific data. All else equal, the increase in the ACR values increases the cost of supply and would lead to increasing prices.
- The 2016/2017 BRA procures capacity for the first Delivery Year beyond the compliance deadline plus a possible one year compliance extension to April 16, 2016 for the EPA MATS rule finalized in 2012, and for compliance with the New Jersey High Electricity Demand Day (HEDD) rule that institutes a NOx emission rate standard on intermediate and peaking units in the state goes into effect on May 1, 2015. RPM market rules allow Generation Capacity Resources to reflect in their offers the costs associated with new investment such as environmental retrofits over multiple years. However, if such investments go into service as scheduled for the 2015/2016 Delivery Year, those costs are sunk and not avoidable in subsequent Delivery Years beginning with the 2016/2017 Delivery Year, but could still be represented in offers. The effect of reflecting these costs in offers, to the extent resources do so, has the effect of increasing the cost of supply and by extension increasing capacity prices. If generators opted to reflect the cost of pollution control retrofits beyond the time they would be sunk, these cost would most likely to be reflected in the offers of coal unit subject to MATS and small peakers in New Jersey subject to HEDD.



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- Expected net energy market revenues which would go toward offsetting fixed, going forward costs including the costs of new investment in new resources as well as investments in existing resources such as environmental retrofits. As discussed above, the net energy market revenues for gas units has increased and would have the effect of lowering the cost of supply and putting downward pressure on prices. However, recent low energy market prices associated with low gas prices have reduced expected net energy market revenues for coal resources. This increases the capacity market price needed to cover fixed, going forward costs, and consequently puts upward pressure on capacity prices if these resources were need to clear the capacity market to maintain resource adequacy.

Overall Effects on Market Outcomes

On balance, with only a minimal increase in the demand for capacity as represented by VRR Curve, the results of the 2016/2017 BRA have been driven by supply-side effects. Overall, increased supply through new entry, uprates, and a significant increase in imports that overwhelms the decrease in available Demand Resources leading to the \$76.63/MW-day decrease in price for Annual Resources in the RTO and \$48.33/MW-day decrease for Annual Resources in MAAC. The price decrease in ATSI from \$357/MW-day down to \$114.23/MW-day for Annual Resources is also driven by the same supply and demand balance in RTO and MAAC, but also is due to the significant transmission investments that have been placed in the RTEP to alleviate reliability criteria violations that resulted from the unprecedented concentration in retirements announced prior to the 2015/2016 BRA.

The only LDA in which prices increased, PSEG, is historically transmission constrained, and did not attract much of the new entry and uprates that are internal to PJM and could not fully benefit from the new entry in other parts of PJM and the increased imports due to the transfer limits into PSEG. Additionally, of the 2,710 MW of announced deactivations since the last BRA, the PSEG zone accounted for 1,408 MW or just over half of the total deactivations in all of PJM since the last BRA, and none of the withdrawn deactivations were located in the PSEG zone. PSEG also experienced a 165 MW decline in cleared Demand Resources that follows the 168 MW decrease in Demand Resources seen in the 2015/2016 BRA.

Finally, there are just over 9,485 MW UCAP (10,195 MW ICAP) of coal-fired capacity that did not clear the BRA. It would seem these coal resources, in addition to needing further investment to continue in commercial operation and possibly reflecting environmental investments that have already been made, may also not be earning sufficient energy market revenues that would keep their capacity market offers lower. Still, with all the competitive new entry, uprates, and imports, these uncleared coal resources were not necessary to reach a record 21.1% installed reserve margin resulting from the 2016/2017 BRA.

EXHIBIT TFC-7

44242--04-24-13

2 Are you saying that off-system
3 sales -- I was just trying -- there seemed to
4 be an inconsistency, so I was just trying to
5 clarify.

6 A. I apologize if I was inconsistent. My
7 understanding is that off-system sales
8 wholesale margins do not go to the ratepayer.

9 Q. Do not?

10 A. Yes, do not.

11 Q. So they go to the shareholders?

12 A. I think that's the only other place for them
13 to go.

14 Q. Okay. And if you refer to subsection (c), it
15 says for modeling purposes, IP&L assumed that
16 100 percent of off-system sales margin go to
17 customers or ratepayers.

18 MS. NYHART: Your Honor, I'm going
19 to object to the question. This
20 cross-examination exhibit is a copy of an IPL
21 response to one of Joint Intervenor's data
22 requests. And it is specifically directed to
23 the surreply testimony of Charles Adkins at
24 page 29, lines 10 and 11. And Mr. Adkins
25 would be the witness to discuss this cross-

79

‡

1 examination exhibit with.

2 This line of questioning is beyond
3 the scope of Mr. Crawford's testimony. He's
4 not been shown to be a rate-making expert or
5 the person who has done the modeling.

EXHIBIT TFC-8

Data Request 7-4. See Surreply testimony of Charles Adkins, p. 28 lines 17-18.

- a. Has Mr. Adkins performed an analysis in which he “properly removed” “associated expenses” for off system sales at Petersburg units 1, 2, 3, & 4 (individually) and/or Harding Street 7?
- b. If not, why not?
- c. If so, provide present value revenue requirements (PVRR) for retrofitting each of Petersburg 1, 2, 3, and 4 and Harding Street 7 (individually).
- d. Provide supporting workpapers, model outputs, and documentation for any analysis conducted as above.

Objection: IPL objects to Request 7-4 on the grounds and to the extent the request seeks a compilation, analysis or study that IPL has not performed and to which IPL objects to performing.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

- a. No. However, it is not necessary to perform this analysis as explained in IPL’s response to CAC-SC DR 7-5(d) below.
- b. Mr. Adkins has not performed such an analysis because he does not possess the data needed to fix Witness Fisher’s error in accounting for off-system sales.
- c. N/A.
- d. N/A.

EXHIBIT TFC-9—CONFIDENTIAL

Request No. 15: Refer to pages 6 and 7 of the Comings Direct Testimony. Beginning on line 24 of page 6, Mr. Comings states "I have substituted the Company's energy price forecasts with a more reasonable forecast based on the relationship of the Company's broker values for energy from 2013 through 2017 compared to its projected natural gas prices for that period."

- a. Please provide the basis for Mr. Comings' contention that using the historic relationship between brokered values for energy compared to the projected natural gas prices constitutes a "more reasonable" forecast. Include any analysis, studies, or other evaluations performed by Mr. Comings that support his contention.
- b. Is this conclusion based solely on Mr. Comings' professional experience and opinion? Please explain the response.

Response No. 15:

- a. Please refer to pages 14 and 15 of Mr. Comings' direct testimony.
- b. Mr. Comings' opinions and conclusions are based on professional experience and the work of others (including other utilities).

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 16
Respondent: Tyler Coming

Request No. 16: Refer to page 7 of the Comings Direct Testimony. At line 1 Mr. Comings states "This adjusted forecast also matches closely with the Company's actual bid prices for energy from 2013 through 2017." What does Mr. Comings mean by "the Company's actual bid prices"?

Response No. 16:

This refers to the "broker value" provided by EKPC in Response to PSC Staff Data Request 5.

Request No. 17: Refer to page 10 of the Comings Direct Testimony, lines 11 through 17. Mr. Comings states "The Company appears to be attempting to maximize net revenues from energy and capacity markets rather than focusing on meeting its own capacity and energy requirements." He further states "In this way, the Company is making a decision very much like a merchant generator, except that captive ratepayers are 'on the hook' if EKPC's market projections are incorrect."

- a. Please explain the basis and rationale for these statements. How is "attempting to maximize net revenues from energy and capacity markets" inconsistent with "focusing on meeting its own capacity and energy requirements"?
- b. Is Mr. Comings suggesting that the ratepayers are not at risk if the Company does not acquire additional energy and capacity resources?
- c. Is Mr. Comings suggesting that ratepayers are not at risk if the Company selects one or more proposals other than the Cooper Unit 1 remediation proposal?
- d. Did Mr. Comings review EKPC's response to the Commission Staffs Initial Data Request, Response 5 that shows the "Ratio of Generation to Load" column in AA of worksheet "Proposal Evaluation_Energy Production"?
- e. Does that information not indicate that the Company is indeed viewing the amount of generation each proposal would provide in relation to its native load requirements?

Response No. 17:

- a. Maximizing net revenues may lead a company to go well above and beyond its capacity and/or energy requirements.
- b. As indicated by Mr. Comings' direct testimony (e.g. page 50), ratepayers are more at risk with the selection of the Cooper Unit 1 project compared to specific other options.
- c. See answer (b) above.
- d. Yes.
- e. Yes. However, this calculation is provided for energy, not capacity.

Request No. 18: Refer to page 10 of the Comings Direct Testimony, lines 18 through 20. Mr. Comings states that EKPC has not provided the projected costs of operating the Cooper Unit 1. Does Mr. Comings understand that the Cooper Unit 1 retrofit was one of the proposals submitted in response to the Request for Proposals ("RFP") and the costs for that project were provided in the same manner as for other proposals submitted in response to the RFP?

Response No. 18:

Yes. The costs provided show the incremental costs of the Cooper 1 project. However, as explained on page 51 of Mr. Comings' direct testimony, the Company did not provide the historical and projected costs of operating the unit itself. The Commission agreed with Intervenors that they were entitled to this data in its December 10th order.

Request No. 19: Refer to page 11 of the Comings Direct Testimony, lines 7 through 9. Mr. Comings states that "In the worst case (if Cooper unit 1 is not dispatched sufficiently to cover its own costs), ratepayers will also be stuck with stranded investments."

- a. What does Mr. Comings believe will happen to the investment already made in Cooper Unit 1 if it is not retrofitted but is rather retired?
- b. How does the magnitude of that stranded investment compare to the amount requested for the retrofit?

Response No. 19:

- a. As for any other utility, recovery of any prior investments made in a retiring unit would depend on future decisions of the Commission.
- b. Mr. Comings has not measured the magnitude of a stranded investment related to the project.

Request No. 20: Refer to page 12 of the Comings Direct Testimony. In discussing the energy price forecasts used in EKPC's analysis, Mr. Comings states that the approach used for a specific two- year period appears "unreasonable and arbitrary".

- a. Please provide the basis for Mr. Comings' contention the approach is "unreasonable and arbitrary". Include any analysis, studies, or other evaluations performed by Mr. Comings that support his contention.
- b. Is this conclusion based solely on Mr. Comings' professional experience and opinion? Please explain the response.
- c. Please provide all energy price forecasts that are publicly available and are from recognized sources that he is personally familiar with and accepts as reasonable.

Response No. 20:

- a. See Mr. Comings' direct testimony pages 12 through 16.
- b. No. Mr. Comings also consulted others who were subject to the confidentiality agreement with the Company.
- c. Almost all utility energy price forecasts reviewed by Mr. Comings in the past have been confidential, with binding confidentiality agreements; the only exception is the Energy Information Administration's Annual Energy Outlook, which can be found here <http://www.eia.gov/oiaf/aeo/tablebrowser/>. It is notable that the EIA AEO Early Release 2014 projects (for the SERC Central region where EKPC is located) that end-use energy prices for all consumer classes (residential, commercial, industrial and transportation) and costs of generation alone are expected to fall or stay flat in real terms from 2012 through 2040-in contrast to the Company's expectations.

Request No. 21: Refer to page 13 of the Comings Direct Testimony. In response to the question "Where does the Company obtain its energy market price forecasts?" Mr. Comings responds "The energy price forecast is produced by ACES Power Marketing ('ACES'), an 'energy marketing agent' owned by EKPC and other cooperatives. EKPC President and CEO, Mr. Anthony Campbell, serves as a board member of ACES." Mr. Comings further points out that an independent auditor "expressed some concern ... that ACES may not be sufficiently independent."

- a. How does Mr. Comings think the independence of ACES Power Marketing, or lack thereof, affects the energy price forecasts it provides to EKPC? What is the basis for your opinion?
- b. How does Mr. Comings think the independence of ACES Power Marketing, or lack thereof, affects the energy price forecasts Wood Mackenzie provides to ACES Power Marketing? What is the basis for your opinion?

Response No. 21:

- a. An independent energy price forecast, which many utilities choose to procure, could provide more credibility since it could not be seen as generating a conflict of interest.
- b. Mr. Comings cannot speculate on how the independence of ACES affects the energy price forecasts.

Request No. 22: Refer to pages 13 and 14 of the Comings Direct Testimony, beginning at line 7 on page 13. Mr. Comings states "It is notable that in the docket wherein EKPC requested membership in PJM (Case No. 2012-00169), the Company noted that an independent auditor (Liberty Consulting Group) 'recommended that 'EKPC should hire an independent consultant to determine the costs and benefits of ISO membership,' and further 'expressed some concern in its report that ACES may not be sufficiently independent.'"

- a. Was Mr. Comings aware that EKPC hired Charles River Associates to be its independent consultant for the benefit cost analysis of joining an ISO?
- b. Please explain the relevance of Mr. Comings' statements to the current case and EKPC's use of the ACES energy price forecast?

Response No. 22:

- a. Yes.
- b. This is relevant since ACES is involved in the energy price forecasts for the current case.

Request No. 23: Refer to pages 14 through 16 of the Comings Direct Testimony, where Mr. Comings discusses his adjustments to the energy price forecast.

- a. On page 14, lines 5 and 6, Mr. Comings states that an indicated price jump in the ACES energy market price forecast is unreasonable and unlikely. Please provide the basis for this conclusion. Include any analysis, studies, or other evaluations performed by Mr. Comings that support his conclusion.
- b. On page 14, lines 6 through 8, Mr. Comings challenges the reasonableness of the long-term Wood Mackenzie forecast. Would Mr. Comings agree that the firm of Wood Mackenzie is an established firm, it is accepted as an industry expert, and its forecasts are widely accepted in the electric power industry? If the response to any part is "no", please explain why in detail.
- c. On page 14, lines 10 through 15, Mr. Comings discusses his methodology using an implied marginal heat rate applied to natural gas prices going forward. He states "This methodology assumes that the energy prices in the future will continue to track with natural gas prices in a similar manner." Please explain in detail why it is reasonable to assume this relationship will continue in the future. Include any analysis, studies, or other evaluations performed by Mr. Comings that support this assumption.
- d. On page 15, line 6, Mr. Comings states "[I]n recent years, energy and natural gas prices have been correlated." Please explain the basis for this statement. If it is based on numerical analysis of electric energy and natural gas price data, please identify the data used and the analysis applied to reach this conclusion, including the delivery points for electricity and natural gas, the start and end dates of the analysis period, the frequency of the data (i.e., hourly, daily, monthly), the computational procedure(s) used, and the numerical results.
- e. On page 16, lines 10 through 12, Mr. Comings cites a pair of factors that allegedly make his adjusted energy price forecast reasonable. Please explain in detail how the cited factors support the conclusion that his adjusted energy price forecast is reasonable.

Response No. 23:

- a. A projected [REDACTED] increase in real energy prices (i.e. after inflation) in three years is unreasonable without a significant natural gas price increase or major policy impact in this period. This is explained further in Mr. Comings' direct testimony on pages 12 through 16.
- b. Mr. Comings would agree that Woods Mackenzie forecasts are used by other utilities but has no opinion of the firm's reputation or the wide acceptance of its forecasts.
- c. The Woods Mackenzie energy price forecast appears to be inconsistent with the Company's natural gas price forecast. Mr. Comings' methodology assumes that the relationship between the Company's natural gas price forecasts and broker value energy prices are consistent throughout the analysis period.
- d. Mr. Comings looked at historical, monthly Locational Marginal Price for AEP-Dayton Hub compared to Henry Hub natural gas prices from 2007 through June of 2013.
- e. These points are explained on pages 15 and 16 of Mr. Comings' direct testimony.

Request No. 24: Refer to page 15 of the Comings Direct Testimony, lines 6 through 9. Mr. Comings states "Given the [REDACTED] in energy prices shown in the Company's energy price forecast, one would expect a [REDACTED] in natural gas prices or a major policy change-such as the addition of a carbon policy."

- a. How does Mr. Comings define the [REDACTED] as he applied it to energy prices?
- b. Are natural gas prices and "major policy changes" the only factors that can cause a [REDACTED] in electric energy prices? If the answer is "yes", please provide the basis for Mr. Comings' opinion. If the answer is "no", please identify the other factors that could cause this "change" in energy prices.
- c. Do environmental regulations in place and/or prospective environmental regulations constitute "major policy changes"? If so, did Mr. Comings consider the possibility that they are the cause of the [REDACTED] in the energy price forecast provided by ACES Power Marketing?
- d. Aside from the alternative energy price forecast Mr. Comings constructed for his direct testimony in this case, did Mr. Comings consider any third-party energy price forecasts? If so, please identify those forecasts and explain why Mr. Comings chose not to use them for purposes of his valuation analysis in this case.

Response No. 24:

- a. This refers to the [REDACTED] increase in real energy prices from 2017 to 2020 in the Company's forecast.
- b. No. The Wood Mackenzie energy price forecast could be based on a higher gas price forecast than what the Company is assuming and/or a significant switch from coal to natural gas generation due to environmental regulations. If Wood Mackenzie's energy price forecast is based on a higher natural gas price than the Company's, this would be inconsistent. If Wood Mackenzie's energy price forecast is influenced by upcoming environmental regulations, it is inconsistent with the Company's assumptions that these regulations will not have an impact.
- c. See response (b).
- d. No.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 25
Respondent: Tyler Coming

Request No. 25: Refer to page 16 of the Comings Direct Testimony, lines 8 through 10. Mr. Comings states "In fact, the Company has chosen to use a forecast that [REDACTED]. What is the basis for Mr. Comings' conclusion that the ACES Power Marketing electric energy price forecast does not include costs associated with a [REDACTED]?"

Response No. 25:

The Wood Mackenzie forecast is referred to as [REDACTED] as indicated by EKPC's Response to PSC Staff data request 5.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 26
Respondent: Tyler Coming

Request No. 26: At several points in Mr. Comings' direct testimony he refers to "the Company's" energy price forecast (e.g. page 15, line 8) and "the Company's" natural gas price forecast (e.g. page 15, line 12). Given that Mr. Comings identified ACES Power Marketing as the source of the price forecasts, does he mean to suggest that ACES Power Marketing provides different price forecasts depending on the identity of its client?

Response No. 26:

“The Company’s” refers to the forecast that the Company procured for this filing and is being used in this filing as part of the Company’s effort to justify its investment.

Request No. 27: Mr. Comings insists throughout his testimony that EKPC has ignored potential carbon costs in the future, as well as other environmental costs. EKPC stated that the future market prices should have a reflection of what the market thinks appropriate costs should be. However, Mr. Comings is adamant that the price forecast used is overstated because it does not follow the recent gas to power price ratio format.

- a. Does the current gas to power price ratio include the future costs of environmental rules?
- b. If not, why is it unreasonable to think that the forecast supplied is incorrect?
- c. The label on the workbook indicated that an explicit adder for carbon was not taken into account in the forecast. Please explain in detail why Mr. Comings apparently assumed that the market indicators did not factor in the expected impacts of carbon.
- d. Please explain in detail why Mr. Comings believes that the current gas to power price ratio will remain constant into the future with the addition of new environmental regulations.

Response No. 27:

- a. Based on the information provided, it is unclear what environmental regulations were incorporated into the Company's natural gas or energy price forecasts, other than the fact that the Wood Mackenzie forecast apparently does not include costs of [REDACTED]
- b. See response (a).
- c. See response 25. If the energy price forecast used by EKPC in this proceeding did incorporate the effects of future carbon regulations, then the Company should have applied the corresponding carbon costs to the cost of operating its generating units.
- d. Mr. Comings' cannot speculate on this since his energy price forecast did not reflect the costs of new environmental regulations (i.e. other than those that may be implicit in the Company's natural gas price forecasts and broker value energy prices).

Request No. 28: Refer to page 20 of the Comings Direct Testimony, lines 12 through 17. "Cooper unit 1 and the rest of the Company's fleet are subject to economic dispatch among other plants in PJM. Generally, the PJM energy price must be sufficient to cover the operating cost of each unit for it to operate. The adjusted energy prices would mean Cooper unit 1 would get dispatched less often than with the Company's energy price forecast, further decreasing the valuation of the project." Please explain why correcting Mr. Comings' valuation numbers for the economic dispatch corresponding to his adjusted energy prices would decrease his valuation of Cooper Unit 1.

Response No. 28:

If Cooper unit 1 is dispatched less often—all else equal—it would recover less revenue from the market and, therefore, would carry a lower market valuation.

Request No. 29: Refer to pages 23 through 25 of the Comings Direct Testimony, where Mr. Comings discusses the capacity price projections. In this discussion, Mr. Comings states that he substituted the projected capacity price for the 2016/2017 delivery year with the May 24, 2013 results from the PJM capacity auction for 2016/2017. However, for the remaining years of the analysis, Mr. Comings did not adjust or alter the capacity price projections.

- a. Please explain in detail why it is reasonable to adjust only the 2016/2017 projected capacity price to the actual results of the PJM capacity auction for that time period.
- b. If the results of the PJM capacity auction for 2016/2017 had been higher than the projected capacity price, would Mr. Comings have adjusted the projected capacity price for that year? Please explain the response.
- c. Given how the results of the 2016/2017 PJM capacity auction were different than the projected capacity price for that period, please explain in detail why Mr. Comings was willing to keep the capacity prices the same as the EKPC forecast for delivery years after 2016/2017. Include any analysis, studies, or other evaluations performed by Mr. Comings that support this approach.

Response No. 29:

- a. Mr. Comings updated the capacity prices to incorporate the latest data available. He does not offer an alternative capacity price forecast past the 2016/2017 delivery year.
- b. Yes. The most up-to-date capacity price would have been included regardless of whether it had been higher or lower than the Company's estimate.
- c. Mr. Comings does not have a sufficient basis for offering an alternative capacity price forecast to the Company's forecast past the 2016/2017 delivery year.

Request No. 30: Refer to pages 25 through 27 of the Comings Direct Testimony. On page 26, line 5 is the question "What are the key risks and benefits associated with the wind PPA?" Mr. Comings replies "The wind PPA carries the risk that energy market prices will be even lower than the cost of energy quoted in the PPA (see Figure 10, above). However, the energy cost of the wind remains lower than even my adjusted all-hours energy price forecast; therefore this risk is low."

- a. After factoring in the 2016/2017 PJM capacity auction results and Mr. Comings adjusted energy price forecast, provide the revised NPV of the wind PPA.
- b. What is the probability in each year from 2015 through 2035 that the all-hours energy price outcome is below Mr. Comings' adjusted all-hours energy price forecast for the same year?
- c. Did Mr. Comings consider risks associated with the cost and availability of transmission incorporated in his assessment of the wind PPA? If not, explain why not. If so, explain how Mr. Comings came to the conclusion that these risks were not "key"?
- d. Did Mr. Comings consider risks associated with changes in PJM markets and market rules in his assessment? If not, explain why not. If so, explain how Mr. Comings came to the conclusion that these risks were not "key"?
- e. Did Mr. Comings consider the risk of supplier default in his assessment? If not, explain why not. If so, explain how Mr. Comings came to the conclusion that this risk was not "key"?
- f. Would Mr. Comings agree that there are credit risks associated with entering into a long-term PPA? Please explain the response.
- g. Please refer to Figure 10 on page 26. Based on the information contained on this graphic, please indicate whether the greatest value of the wind PPA occurs at the beginning or end of the period.
- h. When considering forecasts of market prices, please indicate whether the near-term or long-term price forecasts are likely to be more accurate.

Response No. 30:

- a. Mr. Comings has not calculated this value.
- b. Mr. Comings did not calculate this probability.
- c. Yes. However, those risks were already analyzed by the Brattle Group.
- d. To some extent. Mr. Comings discusses the PJM energy price risk (page 26, lines 6-9). However, he did not consider changes to PJM market rules.

- e. No. Supplier default risk (if any) would apply to any PPA.
- f. Yes, in that, through traditional ratemaking, the Company self-build options would be added to ratebase whereas a PPA would be recovered as an expense.
- g. The undiscounted value of the wind PPA increases with each year compared to Mr. Comings' energy forecast.
- h. In general, near-term forecasts are more likely to be accurate than long-term forecasts.

Request No. 31: Refer to pages 28 through 40 of the Comings Direct Testimony. In this section of his testimony, Mr. Comings criticizes EKPC for not including in its analysis any compliance costs associated with the following environmental regulations:

- 1) Emerging National Ambient Air Quality Standards ("NAAQS").
- 2) Re-issuance of the Cross State Air Pollution Rule ("CSAPR").
- 3) Rules governing the disposal of Coal Combustion Residuals ("CCR").
- 4) Provisions of the Clean Water Act, Section 316(b), governing cooling water intake structures.
- 5) Clean Water Act effluent limitation guidelines for scrubber and ash handling wastewater at steam electric generating units.

- a. Would Mr. Comings agree that none of the five listed environmental regulations has been finalized and currently in force? Please indicate "yes" or "no" for each regulation.
- b. Would Mr. Comings agree that it is likely that each of the five listed environmental regulations could face challenges in the court system after being finalized? For any regulation where Mr. Comings' response is "no", please explain in detail why the response is no.
- c. Would Mr. Comings agree that until each of the five listed environmental regulations are finalized and in force, the specific compliance plan to satisfy the regulation cannot be determined? For any regulation where Mr. Comings' response is "no", please explain in detail why the response is no.
- d. Would Mr. Comings agree that until each of the five listed environmental regulations are finalized and in force, the specific costs of compliance cannot be determined? For any regulation where Mr. Comings' response is "no", please explain in detail why the response is no.

Response No. 31:

- a.
 - 1) Yes.
 - 2) Yes.
 - 3) Yes.
 - 4) Yes.
 - 5) Yes.
- b. Parties are able to file court challenges to finalized EPA rules. Therefore, it is possible that parties will challenge any of the five listed rules, just as the MATS rule for which EKPC has proposed a compliance plan in this proceeding is still

being challenged in federal court.

- c. A reasonably prudent utility should develop a range of potential compliance plans based on the proposed rule. EKPC is assuming that it will not incur future costs from these regulations. This assumption means that EKPC is certain that the future costs will be \$0, which is an unreasonable assumption as Mr. Comings explains in his testimony (e.g. page 29).
- d. See response (c).

Request No. 32: Refer to page 31 of the Comings Direct Testimony, lines 4 through 9. Mr. Comings acknowledges that the impact of these various environmental rules cannot be known with absolute certainty. He further states "Until each rule is finalized, and until the state and EPA determine compliance mechanisms for electric generating units that violate these rules, the exact timing and impact of these rules is unknown."

- a. Given this acknowledgment by Mr. Comings, please explain in detail why he believes EKPC should have evaluated "proxy" compliance costs.
- b. Would Mr. Comings agree that while several of these regulations are in draft form, until the regulations are finalized, survived court challenges, and in force, the appropriate compliance approach and associated compliance costs cannot be accurately determined?

Response No. 32:

- a. EKPC is assuming that Cooper unit 1 will not incur compliance costs from future environmental rules that at present are required to be finalized in 2014-2015. This assumption reflects a certainty on the Company's part that the costs will be \$0. By contrast, a reasonable approach would evaluate the range of regulatory options under consideration (as reflected in the proposed rules), estimate costs for that range of regulatory options, and factor those costs into the utility's planning, instead of simply turning a blind eye to those regulations by assuming a certain cost of \$0.
- b. Mr. Comings does not agree with the premise of the question, because future costs are usually estimated, not "known" in advance. EKPC relies on forecasts of future coal, natural gas, and energy prices, even though they are uncertain; there is no reason EKPC cannot do the same for future environmental compliance costs. Ignoring the potential costs associated with these regulations does not mean that costs will not be incurred in the future. See response (a)

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SC Response to EKPC Requests
Item No. 33
Respondent: Tyler Coming

Request No. 33: Refer to page 32 of the Comings Direct Testimony, lines 13 through 17. Concerning the NAAQS, Mr. Comings identifies the standard that "most likely" will impact EKPC's solid- fueled assets in this case. Please explain in detail how Mr. Comings determined which NAAQS would "most likely" impact EKPC. Include any analysis, studies, or other evaluations performed by Mr. Comings that support his conclusion.

Response No. 33:

This is explained in Mr. Comings' Direct Testimony on pages 31 through 35.

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SC Response to EKPC Requests
Item No. 34

Respondent: Kristin Henry, Sierra Club counsel, and Tyler Comings

Request No. 34: On April 2, 2012, the Big Rivers Electric Corporation ("Big Rivers") filed with the Commission Case No. 2012-00063, an application seeking a Certificate of Public Convenience and Necessity ("CPCN") for several capital projects it proposed to construct that would bring its generating units into compliance with the requirements of CSAPR and the Mercury and Air Toxics Standards rule. The total capital investment was \$283.49 million. On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR. On August 22, 2012, the Sierra Club and other intervenors in the case filed motions requesting that the Commission deny without prejudice Big Rivers' CPCN citing the decision of the D.C. Circuit Court of Appeals.

- a. Was Mr. Comings aware of this Kentucky proceeding?
- b. Mr. Comings argues that EKPC should be incorporating compliance costs for the yet to be reissued CSAPR, which has not been finalized and could undergo court challenges once it is issued. However, when the Sierra Club was an intervenor in a case that was based on complying with the original CSAPR while it was on appeal, as soon as an appellate court vacated the original CSAPR, the Sierra Club moved that the application be denied without prejudice. Would Mr. Comings agree that there appears to be some inconsistency between his position and the position his client has taken in a previous case? If no, please explain why not.

Response No. 34:

- a. Yes. (Tyler Comings)
- b. Sierra Club objects on the grounds that Mr. Comings was not involved in drafting the motions to dismiss in Case No. 2012-00063, and therefore the question relates to matters outside the scope of the witness's experience and expertise. (Kristin Henry)

Subject to and without waiving the foregoing objections, Sierra Club responds that there is no inconsistency between the Club's positions in Case No. 2012-00063 and the present case. Sierra Club takes the position that electric utilities should account for all reasonably foreseeable environmental compliance costs during the relevant planning horizon, based on the best information available at the time of the decision. The question at issue in the motion to dismiss in the Big Rivers proceeding, however, was not what costs should or should not be

factored into the utility's resource planning, but rather whether the Commission should issue a CPCN for projects intending to bring Big Rivers' into compliance with CSAPR requirements when CSAPR had just been vacated.

By contrast, here EKPC has ignored reasonably foreseeable costs to comply with environmental rules which EPA has a legal obligation to finalize in 2014-2015. These rules include the cooling water intake rule under Clean Water Act section 316(b), the RCRA coal combustion residuals rule, and Clean Water Act effluent limitations guidelines for power plants. Additionally, the President of the United States has instructed EPA to finalize in 2015 a rule regulating carbon emissions from existing power plants. As discussed in Section 6 of Mr. Comings' direct testimony, the best information available at this time indicates that those rules will result in compliance costs for Cooper unit 1 during the expected lifetime of the proposed compliance project for which EKPC seeks a CPCN.

Request No. 35: Refer to page 37 of the Comings Direct Testimony, concerning the potential cost of compliance with rules governing the disposal of CCR.

- a. Please explain in detail why it is appropriate to utilize the estimated costs of compliance estimated for the Tennessee Valley Authority as a surrogate for the potential compliance costs at Cooper Unit 1.
- b. Beginning at line 9 Mr. Comings states "While I do not have specific engineering knowledge of the conditions at Cooper unit 1, I assume that compliance with the CCR rule at Cooper unit 1 would cost approximately \$41 million (2012\$), assuming conversion to dry ash handling will be required." Since Mr. Comings acknowledges he has no specific engineering knowledge of the conditions at Cooper Unit 1, please explain in detail how he can offer any reasonable estimate of the potential compliance cost for CCR.

Response No. 35:

- a. The Company refused to offer any estimate of costs to comply with the CCR regulation compliance, and objected to providing Intervenors with information on current coal ash handling practices – information that Intervenors could use to develop more accurate cost estimates. In light of EKPC's refusal to provide this data, Mr. Comings used the Tennessee Valley Authority estimate as a surrogate since it was publicly available. If EKPC complies with the Commission's order granting Intervenors' motion to compel by providing Intervenors with information on current waste handling practices at Cooper unit 1, Intervenors may be able to develop additional estimates of the costs to comply with the CCR rule.
- b. See response (a).

Request No. 36: Refer to page 40 of the Comings Direct Testimony, lines 10 through 27.

- a. Beginning at line 12, Mr. Comings states "Under lenient to strict environmental regimes, the Company could see capital compliance obligations of anywhere from \$8 to \$92 million or more at Cooper unit 1." Does not a range of compliance costs of \$84 million support EKPC's position that determining these compliance costs at this time is subject to much uncertainty and speculation? Please explain the response.
- b. Beginning at line 24, Mr. Comings states in part "It is my opinion that a reasonable mid-level estimate of future obligations is the more lenient implementation of environmental rules." Is Mr. Comings in effect suggesting the compliance obligation should be \$50 million? Please explain the response and also explain in detail why the amount is reasonable. Include any analysis, studies, or other evaluations performed by Mr. Comings that support his conclusions.

Response No. 36:

- a. The range of compliance costs results from the rules being in proposed, rather than final, form. Mr. Comings does not agree that the proper way to handle uncertainty in the magnitude of future costs is to assume that the costs will be zero. Instead, reasonable and prudent planning would evaluate the range of regulatory options under consideration (as reflected in the proposed rules), estimate costs for that range of regulatory options, and factor those costs into the utility's planning. Alternatively, the Company is assuming that it will not incur future environmental costs for Cooper unit 1. Therefore, Company's assumption does not reflect any uncertainty since there is no range of possible costs other than \$0.
- b. No. Mr. Comings addresses this in the rest of the paragraph cited above: "...along with the Synapse mid case CO₂ price; however, the Company and this Commission should review the risks of a more stringent environmental regime as well" (Comings Direct, p. 40 lines 25-27).

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SC Response to EKPC Requests
Item No. 37

Respondent: Kristin Henry, Sierra Club counsel, and Tyler Comings

Request No. 37: Refer to pages 41 through 49 of the Comings Direct Testimony.

- a. Despite all the activity concerning the mitigation of carbon dioxide ("CO₂") pollution, would Mr. Comings agree that to date there has been no regulations finalized or in force dealing with CO₂?
- b. Would Mr. Comings agree that regardless of how regulations addressing CO₂ pollution are developed and what statutory authority is utilized to support those regulations, it is likely that any finalized regulations will be challenged in the court system?
- c. Have there already been legal challenges to the EPA's interpretation of the Clean Air Act as it applies to CO₂?
- d. If the regulations are not finalized and are not in force, can Mr. Comings at this time identify the exact compliance strategy and the specific compliance costs for CO₂ EKPC would incur? If yes, please identify the compliance strategy and provide a detailed breakdown of the specific compliance costs. Include any analysis, studies, workpapers, or other evaluations performed by Mr. Comings to support his identified compliance strategy and compliance costs.

Response No. 37:

- a. No. (Tyler Comings)
- b. Parties are able to file court challenges to finalized EPA rules. Therefore, it is possible that parties will challenge the rule, just as some parties continue to challenge the MATS rule for which EKPC is proposing a compliance plan in this proceeding. (Tyler Comings)
- c. In 2007, the United States Supreme Court held that greenhouse gases are an "air pollutant" subject to regulation under the Clean Air Act. *Massachusetts v. EPA*, 549 U.S. 497 (2007). In the subsequent years, parties have filed scores of lawsuits challenging EPA's ability to regulate greenhouse gas emissions under its existing Clean Air Act authority. To date, every one of those lawsuits has failed.

Most notably, the United States Court of Appeals for the District of Columbia Circuit upheld in their entirety four major EPA rules: the finding that greenhouse gases endanger public health and welfare (the so-called "endangerment finding"); EPA's regulation of greenhouse gas emissions from motor vehicles; EPA's

finding that the regulation of GHGs from motor vehicles triggers PSD and Title V permitting requirements for major stationary sources; and EPA's tailoring rule (which modifies the PSD permitting requirements as applied to greenhouse gases). *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (D.C. Cir. 2012).

On October 15, 2013, the United States Supreme Court granted a petition for certiorari to review the narrow question of whether EPA's regulation of greenhouse gas emissions from new motor vehicles triggers PSD permitting requirements for stationary sources. The Supreme Court denied petitions to review the D.C. Circuit's decision to uphold EPA's endangerment finding and EPA's regulation of greenhouse gas emissions from motor vehicles. (Kristin Henry)

- d. Mr. Comings discusses possibilities for compliance throughout his direct testimony. The 2013 Synapse Carbon Dioxide Price Forecasts are meant to provide a proxy for future costs of compliance with carbon regulations, and sets forth a reasonable range of potential future costs. By contrast, EKPC has offered certainty on this topic by assuming that there will be no costs related to its plants' carbon emissions over the entire planning period. (Tyler Comings)

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SC Response to EKPC Requests
Item No. 38
Respondent: Tyler Comings

Request No. 38: Refer to page 42 of the Comings Direct Testimony, lines 11 through 15, and Exhibit TFC-4, page 12. While the Idaho Public Utilities Commission ("Idaho Commission") did state that it seemed likely the EPA would move forward and enact additional regulations regarding CO₂, the Idaho Commission also stated "The Commission also acknowledges that recent history has demonstrated that attempts by energy analysts to predict carbon pricing is fraught with failure and uncertainty." Does Mr. Comings agree with the Idaho Commission's observation concerning energy analysts' attempts at predicting carbon pricing? Please explain the response.

Response No. 38:

See responses 32(a) and (b), and 37(d).

Request No. 39: Refer to page 47 of the Comings Direct Testimony, beginning at line 18, and Exhibit TFC-3.

- a. Does Mr. Comings agree that EPA has indicated it would seek state input in developing CO₂ emission standards under Section 111(d) of the Clean Air Act?
- b. On page 2 of the October 22, 2013 letter to EPA Administrator McCarthy, Secretary Peters states: "Kentucky is committed to reducing its greenhouse gas emissions, but we will not put our citizens and industries in the untenable position of having to forego economic prosperity to achieve these reductions." Secretary Peters also states: "As the state most- dependent on coal-fired generation and one with the most energy-intensive manufacturing economy, Kentucky has much at stake if national policies do not take into account the variations among the states in establishing existing source guidelines." Would Mr. Comings agree that Secretary Peters clearly argues that any existing source CO₂ regulations need to take into consideration the specific situation existing in each of the states?
- c. Would Mr. Comings agree that carbon price forecasts such as Synapse's 2013 Carbon Dioxide Forecast, Exhibit TFC-10, addresses carbon prices from a national point of view rather than a state by state approach?

Response No. 39:

- a. Yes.
- b. Yes.
- c. Yes.

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Item No. 40
Respondent: Tyler Comings

Request No. 40: Refer to page 48 of the Comings Direct Testimony, lines 14 through 20.

- a. Please provide copies of any analysis, evaluations, or other documents by parties independent of Synapse that establishes that the Synapse 2013 Carbon Dioxide Forecast is "a reasonable carbon price forecast".
- b. Since Mr. Comings did not utilize the Synapse 2013 Carbon Dioxide Forecast in his evaluation of the proposed Cooper Unit 1 project, please explain why this document was submitted as part of his direct testimony.

Response No. 40:

- a. The 2013 Synapse Carbon Dioxide Price Forecast was released on November 1, 2013. The only known use of this most recent forecast was in a Synapse study on the Avoided Energy Supply Cost that is used to measure the impacts of energy efficiency programs throughout New England. Attachment 40a lists this study. Attachment 40a also lists other entities (including utilities) that have utilized or referred to past Synapse's Carbon Price Forecasts, through 2009.
- b. As explained in Mr. Comings' direct testimony on page 48, the 2013 Synapse Carbon Dioxide Price Forecast represents a reasonable alternative to the Company's assumption of no costs from carbon regulation. Due to the lack of sufficient information provided by the Company, Mr. Comings was not able to estimate the cost impact from applying this forecast.

| Entity | Entity Type | Year | Report | Links |
|--|-------------|------|---|---|
| Avoided Energy Supply Costs in New England: 2013 Report | Research | 2013 | Hornby, et al., <i>Avoided Energy Supply Costs in New England: 2013 Report</i> . Prepared for the Avoided-Energy-Supply-Component (AES-C) Study Group. July 12 2013 | http://www.synapse-energy.com/Downloads/SynapseReport.2013-07.AESC.AESC-2013.13-029-Report.pdf |
| Idaho Power | Utility | 2013 | Idaho Power 2013 Integrated Resource Plan Advisory Council Materials. | http://www.idahopower.com/AboutUs/PlanningForFuture/irp/2013/IRPAC_Materials.cfm |
| Portland General Electric | Utility | 2013 | PGE Integrated Resource Plan 2013. 2nd Stakeholder Presentation & Discussion. May 28, 2013. | http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/may_28_presentation.pdf |
| U.S. EPA | Research | 2013 | Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units | http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf |
| Kansas City Power and Light Company | Utility | 2013 | KCPCL 2013 Integrated Resource Plan Annual Update. June 2013, Page 24. | https://www.elis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2013-0537&attach_id=2013021365 |
| BC Hydro | Utility | 2012 | BC Hydro 2012 Integrated Resource Plan. Chapter 4: Market Price Forecasts. | http://www.bchydro.com/content/dam/hydro/media/lib/interet/documents/planning_regulatory/iea_itap/2012g2/draft_2012_irp_chapter2.pdf |
| E3 | Research | 2012 | Mahone, Amber. "Economic Impacts from Power Plant Air Pollution". E3 Report to WECC Environmental Data Task Force. Jan 11 2012. | http://www.wecc.biz/committees/BOD/TEPPC/SPSG/EDTF/20120118/Lists/Presentations/1/120111_EDTF_Meeting_Economic_ValueofAirPollution_PPT.pdf |
| RFF | Research | 2012 | Burtraw, D. "Update on the Implementation of AB 32: Cap and Trade in Focus" | http://www.rff.org/RFF/Documents/RFF-CTst-Burtraw-March272012.pdf |
| California Division of Ratepayer Advocates | Research | 2012 | Diana L. Lee and Jordan Parrillo "The Division of Ratepayer Advocates Updated Proposal For Using Cap and Trade Allowance Revenue" Jan. 6, 2012. Rulemaker 11-03-012. | http://www.carbonshare.org/docs/DRAPProposal90percent16-12.pdf |
| Kansas City Power and Light Company | Utility | 2012 | KCPCL 2012 Integrated Resource Assessment. April 2012. Vol 4: Supply-Side Resource Analysis. Page 69. Docket No. EO-2012-0323. | https://www.elis.psc.mo.gov/mpsc/commoncomponents/view_document.asp?DocId=935682054 |
| Union of Concerned Scientists | Research | 2011 | Union of Concerned Scientists. 2011. "A Risky Proposition Appendix A: Key Assumptions for Levelized Cost of Electricity Ranges." | http://www.ucsusa.org/assets/documents/clean_energy/Appendix-A-Key-Assumptions-Levelized-Costs.pdf |
| SINTEF | Research | 2011 | Kalinin, A. Husebye, J, Brunsvold, A. "Impact of CO2 Price Stability on Investment in CCS Technology". SINTEF. | http://www.sintef.no/project/TCC56/Presentations/D5/04%20296-Alexey%20Kalinin%20_TCC56_6_13.pdf |
| Chugach Electric Association | Utility | 2011 | The Regulatory Commission of Alaska. <i>Order Allowing Payments Made to Fire Island Wind, LLC, Under a Power Purchase Agreement to be Collected Through the Fuel and Purchased Power Cost Adjustment; Requiring Reimbursement to Interconnected Utilities for Costs Incurred Because Wind Power from the Fire Island Wind Project is Added to the Railbelt Electric Grid; Requiring Disclosure to Cooperative Members of Cost of Wind Power; Requiring Status Report; and Closing Docket.</i> Docket U-11-100. Order No. 5. October 10, 2011. | http://www.chugachelectric.com/pdfs/agenda/specagenda_101211_v.a.pdf |
| Vermont Department of Public Service | Utility | 2011 | Vermont Department of Public Service. <i>Public Review DRAFT 2011 of the Comprehensive Energy Plan.</i> September 16, 2011. | http://www.vtenergyplan.vermont.gov/ |
| New England Avoided-Energy-Supply-Component Study Group (New England energy efficiency administrators) | Research | 2011 | Hornby, et al., <i>Avoided Energy Supply Costs in New England: 2011 Report</i> . Prepared for the Avoided-Energy-Supply-Component (AES-C) Study Group. July 21, 2011. | http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf |
| Schlumberger Business Consulting | Research | 2011 | Camba, Dr. Raul. <i>Impact of critical fluids for EOR.</i> Presentation at the Enhanced Oil Recovery World Congress, Dubai, UAE. Schlumberger Business Consulting. May 30, 2011. | http://www.sbc.slb.com/Our_Ideas/Executive_Presentations/~/media/Files/Our%20Ideas/Executive_Presentations/SBC_EOR%20Conference%20v4.ashx |
| Hydropower Working Group | Research | 2011 | Electricity Price Outlook for Upper Great Lakes Hydroelectric Facilities. Jan 2011, Prepared by the Interantional Upper Great Lakes Study Team. | http://www.iugls.org/files/Invnce/uploaded/PeerReview.pdf |
| Southern California Edison | Utility | 2011 | Southern California Edison. <i>Testimony of Southern California Edison Company.</i> Docket U 338-E Before the Public Utilities Commission of the State of California. April 20, 2011. | http://www.cpuc.ca.gov/NR/rdonlyres/769DC22C-C1E9-4658-B8C7-38FD8B179729/0/SCF20101TPP35CETestimony_PUBLIC.pdf |
| American Council for an Energy-Efficient Economy | Research | 2011 | American Council for an Energy-Efficient Economy. <i>Advancing Energy Efficiency in Arkansas: Opportunities for a Clean Energy Economy.</i> March 2011. | http://arkansasenergy.org/media/337914/eeo-aceee%20final%20report.pdf |
| Kansas City Power and Light Company | Utility | 2011 | Blunk testimony, page 16, line 15. In the Matter of the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A., Docket No. 11-KCPE-581-PRE. | http://estar.kcc.ks.gov/estar/ViewFile.aspx?Blunk%20Direct%20%20Public.pdf?fid=f3a7d03a-2b15-4562-b8d5-99db8ec77160 |
| University of Michigan | Research | 2010 | Buzzell, G. Q Do, M Irwin, S Mills, M Ott. "Comparing Externalities of Solar Photovoltaic to Natural Gas Electricity Generation". 2010.University of Michigan Master's Project. | http://deepblue.lib.umich.edu/bitstream/handle/2027.42/78398/Ancillary%20Impacts%20of%20Solar%20Photovoltaic%20Power%201210.pdf?sessionid=DD0E203BA348668AC077CA94E1A272F?sequence=1 |
| Pacific Gas & Electric (PG&E) | Utility | 2010 | Middlekauff, Charles. <i>Notice of Availability of Pacific Gas and Electric Company's (U 39 E) Renewable Integration Model and Results.</i> August 16, 2010. | http://www.cpuc.ca.gov/NR/rdonlyres/A3638909-D020-431A-8727-02A763E724EA/0/PGERIMWittenDescription81610.pdf |
| New Hampshire Public Utilities Commission | Utility | 2010 | State of New Hampshire Public Utilities Commission. Order No. 25,111. Unifil Energy Systems, Inc. <i>Petition for Approval Of Investment In and Rate Recovery Of Distributed Energy Resources.</i> Docket DE 09-137. June 11, 2010. | http://www.puc.state.nh.us/regulatory/CASEFILE/2009/09-137/ORDERS/09-137%202010-06-11%20ORDER%20NO%2025.111%20APPROVING%20IN%20PART%20AND%20DENYING%20IN%20PART.PDF |
| PJM | PUC/RTO | 2010 | PJM. <i>2009 Regional Transmission Expansion Plan Report. Section 10: Market Efficiency Analysis.</i> February 26, 2010. | http://www.pjm.com~/media/documents/reports/2009-rtep/2009-section10.ashx |

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|--|----------|------|---|---|
| Brattle Group | Research | 2009 | Weiss, Jurgen and Mark Sarro. <i>The Economic Impact of AB 32 on California Small Businesses</i> . A report prepared for the Union of Concerned Scientists. The Brattle Group, December 2009. | http://www.ucsusa.org/assets/documents/global_warming/AB-32-and-CA-small-business-report.pdf |
| California Public Utilities Commission | PUC/RTD | 2009 | California Public Utilities Commission. <i>Inputs and Assumptions to 33% Renewable Portfolio Standard Implementation Analysis</i> . June 2009. Page 13. And 33PercentRPScalculator.xls. | http://www.cpuc.ca.gov/NR/rdonlyres/932CFFAA-0610-474E-905D-30CD1D76C651/0/inputsandAssumptions_UPDATE.pdf |
| New England Avoided-Energy-Supply-Component Study Group (New England energy efficiency administrators) | Research | 2009 | Hornby, et al., <i>Avoided Energy Supply Costs In New England: 2009 Report</i> . Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group. October 23, 2009. | http://www.synapse-energy.com/Downloads/SynapseReport_2009-10_AESC_AESC-Study-2009-09-020.pdf |

Request No. 41: Refer to page 50 of the Comings Direct Testimony.

- a. Please explain whether Mr. Comings is familiar with the corporate structure of an electric cooperative.
- b. Was Mr. Comings aware that EKPC is a generation and transmission cooperative that is owned by the 16 member distribution cooperatives it sells power to?
- c. Was Mr. Comings aware that the EKPC board of directors is comprised of representatives of each of the 16 member distribution cooperatives?
- d. Was Mr. Comings aware that the EKPC board of directors approved the Cooper Unit 1 project, as shown in Exhibit 2 to the Application?

Response No. 41:

- a. Mr. Comings is generally aware of a cooperative's corporate structure
- b. Yes.
- c. Yes.
- d. Yes.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 42

Respondent: Kristin Henry, Sierra Club counsel, and Jeffrey Loiter

Request No. 42: Please provide a copy of the contract, memorandum of understanding, or other documentation between the Sierra Club and Optimal Energy, Inc. ("Optimal") related to the analysis and testimony performed in conjunction with this case. Specifically, provide the sections of the applicable documents that govern the analysis to be performed by Optimal.

- a. Was Optimal directed by the Sierra Club to produce a totally independent and objective analysis of the proposed EKPC Cooper Unit 1 project or was Optimal directed by the Sierra Club to produce an analysis that conformed with and complimented the "Beyond Coal" campaign? Please explain the response in detail.

Reponse No. 43:

Sierra Club objects on the grounds that the contract between Sierra Club and Optimal Energy is privileged. Subject to and without waiving the foregoing objections, Sierra Club states that it has agreed to pay Optimal Energy \$26,000 for work on this docket. (Kristin Henry)

- a. Yes. Sierra Club asked Optimal Energy to independently review the Company's filing and submit testimony based on its analysis. (Jeff Loiter)

Request No. 43: Please describe any affiliated relationships between the Sierra Club and Optimal. Affiliated relationships can include, but are not limited to:

- a. Investment in Optimal by the Sierra Club.
- b. Corporate ownership of Optimal in total or part by the Sierra Club.
- c. Officers and officials of the Sierra Club holding seats on the Optimal board of directors.

Response No. 43:

There are no affiliated relationships between the Sierra Club and Optimal Energy.

Request No. 44: Refer to pages 2 and 3 of the Loiter Direct Testimony and Exhibit JML-1.

- a. On page 3 of the Loiter Direct Testimony, Mr. Loiter states he has submitted written testimony and/or testified before utility commissions in Arkansas, Virginia, West Virginia, Ohio, Kansas, and Maryland. However, on page 1 of Exhibit JML-1, Mr. Loiter's resume states he has submitted expert testimony in case filings in Virginia, Ohio, Arkansas, Pennsylvania, Maryland, and Missouri. Please explain why there are differences in these two listings and indicate exactly which states Mr. Loiter has submitted written testimony and/or testified before utility commissions.
- b. For each state identified in part a above where Mr. Loiter has submitted written testimony, please provide a copy of the written testimony and identify the case docket number and case style, the utility commission, the utility in the case, and on whose behalf Mr. Loiter was filing testimony. If a final commission order or decision has been issued in the case, please also provide a complete copy of the utility commission's final order or decision.
- c. For each state identified in part a above where Mr. Loiter provided testimony before a utility commission, provide a copy of the transcript of Mr. Loiter's testimony and identify the case docket number and case style, the utility commission, the utility in the case, and on whose behalf Mr. Loiter was testifying. If a final commission order or decision has been issued in the case, please also provide a complete copy of the utility commission's final order or decision.
- d. On page 2 of Exhibit JML-1 it is stated that Mr. Loiter managed Optimal's participation in a team developing a Five-Year Energy Efficiency and Demand Response Plan for the Tennessee Valley Authority ("TVA").
 - 1) Please describe Optimal's and Mr. Loiter's role and responsibility in this team. Were Mr. Loiter and Optimal the team leaders on this project?
 - 2) Did TVA eventually adopt this plan? Please explain the response.

Response No. 44:

- a. There are differences in these two lists because the resume submitted as Exhibit 1 is older and was not intended to be an exhaustive list of all jurisdictions, as noted by the text "have included." The list included in the Direct Testimony omitted Pennsylvania and Missouri because Mr. Loiter neither directly sponsored nor appeared in person to give testimony in cases in those jurisdictions. Rather, he contributed analyses and/or commentary that became part of testimony or filed comments by other parties.
- b. The table below lists all cases where Mr. Loiter submitted written testimony. The right-hand column indicates the case files that Mr. Loiter has in his possession related to each case and that are attached to this response.

| Jurisdiction | Proceeding Number/Dates | On Behalf of: | Nature of Testimony | Files |
|----------------------|--|--|--|--------------------------|
| Virginia SCC | PUE-2009-00023 31 July 2009 | Southern Environmental Law Center | Responses to questions posed by the SCC in evidentiary hearing related to achievable, cost-effective energy efficiency potential, the costs of these savings, and the distribution of savings across the state and by utility. | Direct |
| Virginia SCC | PUE-2011-00092 15 March 2012 | Environmental Respondents | Critique and assessment of Dominion Virginia Power IRP | Direct Final Order |
| Virginia SCC | PUE-2011-00093 17 January 2012 | Environmental Respondents | Comment on application for approval of Dominion Virginia Power DSM programs and associated spending | Direct |
| Virginia SCC | PUE-2012-00128 7 March 2013 | Environmental Respondents | Comment on Dominion Virginia Power application for a CPCN for Brunswick natural gas-fired power station | None |
| Virginia SCC | PUE-2012-00100 15 January 2013 | Environmental Respondents | Dominion Virginia Power application for extension of DSM programs and an administrative approval process for DSM programs | Direct |
| Arkansas PSC | Docket No.06-154-U | General Staff of the Arkansas Public Service Commission | Presentation of three efficiency scenarios for inclusion in modeling related to the need for a coal-fired power plant proposed by Southwestern Electric Power Company. | None |
| Kansas CC | Docket No. 10-KCPE- 795-TAR 15 October 2010 | Climate and Energy Project | Comment on design and cost of KCP&L proposed efficiency programs; identify additional program strategies | None |
| Ohio PUC | 12-2190-EL-POR, 12-2191-EL-POR, 12-2192-EL-POR 5 October 2012 | Sierra Club | Comment on FirstEnergy 2013-2015 Energy Efficiency and Peak Demand Reduction Program Portfolios | Direct |
| West Virginia PSC | 12-1571-E-PC 26 April 2013 | Sierra Club | Comment on petition by FirstEnergy for approval of generation resource transaction | Direct |
| West Virginia PSC | 12-1655-E-PC 18 June 2013 | Sierra Club | Comment on petition by Appalachian Power for approval of generation resource transaction and related relief | Direct |

c. Mr. Loiter provided testimony before a utility commission in all of the above listed cases with the exception of the cases before the Arkansas PSC and the Kansas CC. In addition, Mr. Loiter appeared before the Maryland Public Service Commission at hearings related to utility DSM filings under that state's EmPOWER Maryland legislation in the fall and winter of 2008/2009, but has no transcripts in his possession from these appearances. Case numbers include 9111, 9153, and 9154. The only case for which he has transcripts is PUE-2011-00093, which are attached.

d.

1) Mr. Loiter and Optimal energy were responsible for the portion of the project related to residential and commercial sector efficiency programs. Neither Optimal nor Mr. Loiter were the team leaders.

2) To the best of my knowledge, TVA did not publish the Five-Year Plan. I do not know whether or not TVA adopted any components of the Plan or the recommendations included therein.

**Direct Testimony of Jeffrey Loiter
on behalf of
The Sierra Club
before the
Public Service Commission of West Virginia
Case No. 12-1571-E-PC**

1 **I: Introduction**

2 **Q. Please state your name and business address.**

3 A. My name is Jeffrey Loiter and my business address is Optimal Energy, Incorporated, 14
4 School Street, Bristol, VT 05443.

5 **Q. On whose behalf are you testifying?**

6 A. I am testifying on behalf of the Sierra Club.

7 **Q. Mr. Loiter, by whom are you employed and in what capacity?**

8 A. I am employed as a Managing Consultant by Optimal Energy, Inc, a consultancy
9 specializing in energy efficiency and utility planning. In this capacity, I direct and
10 perform analyses, author reports and presentations, manage staff, and interact with clients
11 to serve their consulting needs. My clients include NGOs, state energy offices and
12 efficiency councils, utilities and third-party program administrators. For example, I
13 participate on the consultant team supporting the work of the Massachusetts Energy
14 Efficiency Advisory Council.

15 **Q. Please summarize your work experience and educational background.**

16 A. I have 15 years of experience in environmental and economic consulting. For the past
17 five years, I have been engaged in a variety of work at Optimal Energy related to energy
18 efficiency program design and analysis. For example, I prepared two documents for
19 inclusion in EPA's *National Action Plan for Energy Efficiency (NAPEE)*: a guidebook on

1 conducting efficiency potential studies, and a handbook describing the funding and
2 administration of clean energy funds.¹

3 In my capacity as a Managing Consultant at Optimal, I also advise clients on
4 efficiency program design and implementation. For example, I recently contributed to a
5 5-year Energy Efficiency and Demand Response Plan for the Tennessee Valley
6 Authority. I have also participated in several studies of efficiency potential and
7 economics, including ones in New York, Vermont, Texas, Massachusetts, and Prince
8 Edward Island. These studies have ranged from macro-level assessments to extremely
9 detailed, bottom-up assessments evaluating thousands of energy efficiency measures
10 among numerous market segments.

11 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
12 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
13 Environmental Engineering from Cornell University and an *M.S.* in Technology and
14 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
15 ER-JML-1.

16 **Q. Have you previously testified before the Public Service Commission of West**
17 **Virginia (“the Commission” or “PSC”)?**

18 **A. No, I have not.**

19 **Q: What is the purpose of your testimony in this proceeding?**

¹ These documents can be found at http://www.epa.gov/cleanenergy/documents/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

1 A: The purpose of my testimony is to comment on the Company's petition for approval of a
2 generation resource transaction and related relief, predominantly concerning the Harrison
3 Power Station.

4 **Q. Are you submitting exhibits along with your testimony?**

5 A. Yes. I have attached my resume as an Exhibit ER-JML-1. In addition, I have attached the
6 following.

7 - Exhibit ER-JML-2: Gunn, R. and M. Thornsjo, "Appalachian Power Co – West

8 Virginia; 2009-2028 DMS Potential Study," Summit Blue Consulting, LLC, November
9 12, 2009.

10 - Exhibit ER-JML-3: Optimal Energy, "Save Money, Create Jobs: How Energy
11 Efficiency Can Work for West Virginia."

12 - Exhibit ER-JML-4: FirstEnergy response to West Virginia Citizen Action Group
13 (WVCAG)'s Second Request for Information Q-15.

14
15 **II: Summary of Conclusions**

16 **Q: Have you reviewed the Company's filing in this matter?**

17 A: Yes, I have review the Company's filing.

18 **Q: Please summarize your conclusions.**

19 A: Based on my review of the filing and a substantial body of other evidence, I have three
20 major conclusions. First, that significant additional demand side resources, both energy
21 efficiency and demand response, are available to offset traditional supply side resources
22 such as those represented by the Harrison acquisition. Second, that greater investment in
23 demand side resources and energy efficiency in particular would provide West Virginia

1 ratepayers and consumers with significant additional benefits beyond immediate savings
2 on their electric bills, in the form of mitigating fuel price risks, promoting local jobs and
3 spending, reducing the need for transmission and distribution upgrades, and general
4 reduced price effects, as explained in more detail below. Third, that the Company's
5 criticisms of efficiency and demand response with respect to their utility as alternatives to
6 supply-side resources are unfounded. Taking these together, I believe that realizing the
7 available energy efficiency potential in the Company's West Virginia service area would
8 save ratepayers up to \$1 billion through 2026 and would in the process create between
9 2,000 and 3,400 jobs for much of the time between now and then.

10 **III: Significant Energy Efficiency is Available to Offset Traditional Supply Side**
11 **Resources and Reduce or Eliminate Load Growth**

12 **Q: In the materials filed in support of their petition for the Harrison Acquisition, did**
13 **the Company consider strategies other than the proposed Harrison plant for**
14 **meeting their load requirement?**

15 **A:** Yes, in this filing the Company compared the proposed Harrison plant acquisition with
16 various other supply-side options such as repurposing the Albright Power station, as well
17 as new coal, nuclear, and combined-cycle natural gas plants.

18 **Q: Did the Company compare the proposed Harrison plant with any demand-side**
19 **resources such as energy efficiency or demand response?**

20 **A:** No, demand-side resources were not seriously considered in either the 2012 Resource
21 Plan or in evaluating alternatives to the Harrison acquisition. No analysis was conducted
22 of the potential for efficiency or other demand-side resources to defer or eliminate the

*Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
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April 26, 2013*

1 need for the plant. Furthermore, the 2012 Resource Plan included as Exhibit A to the
2 filing demonstrates a fundamental misunderstanding of efficiency investments and
3 customer purchasing behavior in general, stating:

4 [I]f an EE [energy efficiency] resource is cost effective for the consumer, it
5 stands to reason that the consumer, when faced with an economic decision
6 of whether or not to install the EE resource, would eventually do so
7 regardless of any out-of-market incentive or utility program.

8 Exhibit A, p. 40.

9 **Q: What about the Company's statement here is troubling you?**

10 **A:** The assumption that customers make perfectly rational economic decisions about all
11 investments is clearly incorrect. No business will succeed by offering a product, however
12 superior to the competition, and simply waiting for customers to buy it. Customers must
13 be informed of the product, be educated about its merits and characteristics, the product
14 must be available to the customers through appropriate sales channels, etc. Furthermore,
15 there are many well-known and well-studied barriers to investments in efficiency
16 measures, including the preference of consumers for lower up-front costs rather than
17 lower total costs of ownership (based in part on barriers to capital investment), and the
18 frequent misaligning of incentives (where the party responsible for owning and
19 maintaining equipment—such as a landlord—and the party responsible for paying the
20 electrical bills—such as a tenant—are different entities). Taken together, these factors are
21 widely recognized as the reason why higher-efficiency equipment is NOT selected by
22 customers and the justification for the existence of efficiency programs in general. The

1 Company's failure to understand or acknowledge this most basic aspect of efficiency
2 programs may explain their failure to include efficiency and demand response from
3 power planning,

4 **Q: Is it appropriate to exclude efficiency and demand response from power planning?**

5 A: No. Decades of experience from across the country have proven EE and DR to be reliable
6 low-cost resources. In order to ensure ratepayers are getting the lowest-cost power
7 available, it is necessary to analyze DR/EE as alternatives or complements to supply side
8 resources.

9 **Q: We will start our discussion with efficiency. How much potential for efficiency do
10 you think is available in FirstEnergy's West Virginia service territory?**

11 A: I believe that FirstEnergy's efficiency programs could be ramped up to achieve annual
12 saving of 1.2% of the total electric load. This would offset a significant amount of the
13 Company's forecasted load growth, and would obviate much of the capacity shortfall the
14 Company claims.

15 **Q: What is this estimate based on?**

16 A: A study prepared by Optimal Energy (including myself) and released in November of
17 2012 by Sierra Club looks at this question in detail.² It surveyed potential studies
18 conducted in states similar to West Virginia and selected studies that 1) relied on similar
19 analytical methodologies; 2) contained the fewest limiting assumptions that would result
20 in an under-estimate of achievable potential; and, 3) had the most similar climatic,

² "Save Money, Create Jobs: How Energy Efficiency Can Work for West Virginia," Prepared for the Sierra Club by Optimal Energy, Inc. 29 November 2012, attached hereto as Exhibit ER-JML-3.

1 geographic, and market conditions to West Virginia. The table below gives a summary of
2 the potential studies considered in the study.

| Energy Efficiency Potential Studies Review & Analysis | | | | | | | |
|---|------------|--------------|-------------------------|--|--|------------|------------|
| State | Study Year | Study Period | Analysis Period (Years) | Annual Achievable Cost Effective Potential | Total Annual Achievable Energy Savings by Sector | | |
| | | | | | Residential | Commercial | Industrial |
| Optimal Energy Estimate | | | N/A | 0.1% | 0.1% | 0.1% | 0.0% |
| Virginia | 2008 | 2008-2025 | 18 | 1.5% | 1.4% | 1.6% | 1.0% |
| Tennessee | 2011 | 2009-2030 | 21 | 0.9% | 0.9% | 1.1% | 0.9% |
| Kentucky | 2012 | 2010-2030 | 21 | 0.9% | 1.4% | 1.3% | 0.6% |
| North Carolina | 2006 | 2007-2017 | 11 | 1.3% | 1.5% | 1.1% | 1.1% |
| Maryland | 2008 | 2008-2025 | 18 | 1.6% | 1.7% | 1.9% | 0.0% |
| Arkansas | 2009 | 2008-2017 | 10 | 0.4% | 0.4% | 0.3% | 0.4% |

3
4 The Optimal “Save Money” report concluded that the studies from Virginia and
5 Tennessee were best suited to provide a conservative estimate of the potential in West
6 Virginia. The report analyzed the total potential estimates in the studies over the study
7 periods to yield an annualized savings estimate for comparison across studies with
8 different time horizons. The 1.2% annual savings number for West Virginia represents an
9 average between the calculated annual percentage potential found for Tennessee and
10 Virginia.

11 **Q: Do you believe this number is reliable enough to be used for power planning**
12 **purposes?**

13 **A:** I believe that 1.2% annual savings is an achievable level of efficiency given an
14 appropriate set of supporting policies and programs. If anything, it is likely to be a
15 conservative estimate of potential, for the following reasons:

- 1 • Most studies of energy efficiency potential do not fully look at the early retirement
2 retrofit market, in which old, inefficient equipment is retired before the end of its
3 useful life and replaced with new, more efficient equipment.
- 4 • As shown below, many other jurisdictions from across the country capture similar
5 levels of savings. Often, these jurisdictions have a long history of running efficiency
6 programs. Initial potential should be higher in West Virginia from lower net-to-gross
7 ratios, greater availability of “low-hanging fruit,” and a history of low retail prices.
- 8 • West Virginia has a very high percentage of manufactured housing and energy
9 intensive industries. Experience has shown that there is typically significant cost-
10 effective savings potential in both of these sectors.

11 Further, the 1.2% annual potential figure is consistent with results reported for
12 Appalachian Power Company, which found an achievable energy efficiency target of
13 approximately 20% of total energy sales in the utility’s territory over the next 20 years.
14 See Gunn, R. and M. Thornsjo, “Appalachian Power Co – West Virginia; 2009-2028
15 DMS Potential Study,” Summit Blue Consulting, LLC, November 12, 2009, attached to
16 my testimony as Exhibit ER-JML-2.

17 **Q: Have utilities or other Program Administrators been able to actually achieve these**
18 **levels of savings?**

19 **A:** Yes, dozens of Program Administrators throughout the country have achieved such levels
20 of efficiency savings: at least twice or three times the levels assumed by the Company.

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- 1 The table below shows utilities in the U.S. with annual sales exceeding 1 million MWh
- 2 that acquired annual efficiency savings excess of 1.1% of sales.³

³ Data from EIA Form 861 for 2011.

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| Utility Name | Ownership | Efficiency as % of Sales |
|---|-----------------------|-------------------------------------|
| Cleveland Electric Illum Co | Investor Owned | 2.6% |
| Massachusetts Electric Co | Investor Owned | 1.7% |
| Southern California Edison Co | Investor Owned | 1.7% |
| United Illuminating Co | Investor Owned | 1.5% |
| PUD No 1 of Clark County - (WA) | Political Subdivision | 1.5% |
| Ohio Edison Co | Investor Owned | 1.5% |
| Los Angeles Department of Water & Power | Municipal | 1.5% |
| Puget Sound Energy Inc | Investor Owned | 1.5% |
| Western Massachusetts Elec Co | Investor Owned | 1.5% |
| Salt River Project | Political Subdivision | 1.5% |
| PPL Electric Utilities Corp | Investor Owned | 1.4% |
| Arizona Public Service Co | Investor Owned | 1.4% |
| Duquesne Light Co | Investor Owned | 1.4% |
| San Diego Gas & Electric Co | Investor Owned | 1.4% |
| Tucson Electric Power Co | Investor Owned | 1.4% |
| Rochester Public Utilities | Municipal | 1.3% |
| Connecticut Light & Power Co | Investor Owned | 1.3% |
| City of Tacoma - (WA) | Municipal | 1.3% |
| The Toledo Edison Co | Investor Owned | 1.3% |
| Duke Energy Indiana Inc | Investor Owned | 1.3% |
| The Narragansett Electric Co | Investor Owned | 1.3% |
| PUD No 2 of Grant County | Political Subdivision | 1.2% |
| Interstate Power and Light Co | Investor Owned | 1.2% |
| Northern States Power Co - Minnesota | Investor Owned | 1.2% |
| City of Pasadena - (CA) | Municipal | 1.2% |
| Idaho Power Co | Investor Owned | 1.2% |
| Snohomish County PUD No 1 | Political Subdivision | 1.2% |
| Pacific Gas & Electric Co | Investor Owned | 1.2% |
| Dayton Power & Light Co | Investor Owned | 1.2% |
| City of Seattle - (WA) | Municipal | 1.1% |
| Nevada Power Co | Investor Owned | 1.1% |
| City of Eugene - (OR) | Municipal | 1.1% |
| Tennessee Valley Authority | Federal | 1.1% |
| City of Burbank Water and Power | Municipal | 1.1% |
| City of Roseville - (CA) | Municipal | 1.1% |
| City of Glendale | Municipal | 1.1% |
| City of Fort Collins - (CO) | Municipal | 1.1% |
| Madison Gas & Electric Co | Investor Owned | 1.1% |

1

1 At the state level, the ACEEE 2012 State Efficiency Scorecard shows 12 states achieved
2 efficiency savings of between 0.5% and 1% of retail sales in 2010 (the most recent year
3 for which data were available),⁴ while an additional 9 states exceeded 1% savings per
4 year.

5 Last, I note that public utility commissions, legislatures, and executive officers in
6 a wide range of jurisdictions have confirmed commitments to targets equal to or greater
7 than this 1.2% annual level, indicating a general consensus regarding the feasibility of
8 such targets. A summary prepared by ACEEE in September 2012 shows that 24 states
9 have enacted long-term (3+ years) binding energy savings targets.⁵ Furthermore, of 20
10 states with EERS policies in place for over 2 years, 13 were achieving at least 100% of
11 their goals and 3 were achieving over 90% of their goals.

12 **Q: What about peak reduction? Are there examples of efficiency programs that have**
13 **yielded significant peak demand savings?**

14 **A:** Yes, programs in various regions and states have demonstrated that significant demand
15 savings are achievable from investment in energy efficiency. Perhaps most notable are
16 California's efforts to cut peak demand during the State's electricity crisis of 2000-2001.⁶
17 Efficiency and conservation-related programs reduced peak demand in California by an
18 estimated 3,668 MW in 2001. In addition, a 2007 study that reviewed 13 case studies of
19 efficiency programs that resulted in large peak demand reductions demonstrated that
20 efficiency programs in states like Texas, California, and Massachusetts had also achieved

⁴ See ACEEE 2012 State Energy Efficiency Scorecard, <http://aceee.org/research-report/e12c>.

⁵ See ACEEE State Energy Efficiency Resource Standard Activity, <http://aceee.org/files/pdf/policy-brief/state-eers-summary-0912.pdf>.

⁶ York, D., Kushler, M., and Witte, P. "Examining the Peak Demand Impacts of Energy Efficiency: A Review of Program Experience and Industry Practice." ACEEE Report Number U072. February 2007.

1 substantial peak reductions, as shown in the table below.⁷ Furthermore, the Sixth
2 Northwest Conservation and Electric Power Plan, prepared by the Northwest Power and
3 Conservation Council, a group charged with developing and maintaining a regional
4 power plan for the Pacific Northwest, projected that the region could meet 85% of the
5 region's load growth over the next 20 years with energy efficiency.⁸ The peak demand
6 reduction potential calculated for the Company is thus readily achievable.

⁷ *Ibid.*

⁸ Northwest Power and Conservation Council, "Sixth Northwest Conservation and Electric Power Plan," February 2010, <http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf>.

Table 2. Energy and Peak Demand Savings of Selected Programs

| State | Program Name | Annual Energy Savings (MWh) | Peak Demand Savings (MW) | MW/GWh* |
|-------|--|-----------------------------|--------------------------|---------|
| CA | San Francisco Peak Energy Program | 56,768 | 9.1 | 0.16 |
| CA | Northern California Power Agency SB5x Programs | 37,300 | 15.9 | 0.44 |
| CA | California Appliance Early Retirement and Recycling Program | — | — | — |
| TX | Air Conditioner Installer and Information Program | 20,421 | 15.7 | 0.77 |
| FL | High Efficiency Air Conditioner Replacement (residential load research project) | — | — | — |
| CA | Comprehensive Hard-to-Reach Mobile Home Energy Saving Local Program | 7,681 | 3.7 | 0.48 |
| MA | NSTAR Small Commercial/Industrial Retrofit Program | 27,134 | 6.0 | 0.22 |
| MA | 2003 Small Business Lighting Retrofit Programs | 35,775 | 9.7 | 0.27 |
| MA | National Grid 2003 Custom HVAC Installations | 980 | 0.17 | 0.17 |
| NY | New York Energy Smart SM Peak Load Reduction Program | — | 15.0 | — |
| MA | National Grid 2004 Compressed Air Prescriptive Rebate Program | 673 | 0.098 | 0.15 |
| MA | National Grid 2003 Energy Initiative Program—Lighting Fixture Impacts | 36,007 | 6.5 | 0.18 |
| MA | National Grid 2004 Energy Initiative and Design 2000plus: Custom Lighting Impact Study | 1,593 | 0.266 | 0.17 |

* This column is derived values from reported peak demand savings and annual energy savings.

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Q: Have you made any specific year-by-year estimates of the potential additional resources?

A: Yes, I have made estimates of the additional efficiency resource, both for energy and capacity. The following table shows my estimates of available efficiency and demand response resources for meeting the Company’s projected load. These demand side resources could represent fully one-third of the Company’s forecast capacity and energy shortfall in 2026.

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| | Capacity (MW) | | Energy (GWh) | |
|------|-----------------------------------|--------------------------------------|------------------------------------|--------------------------------------|
| | Cumulative DSM Savings (MW) | As a % of 2012 forecasted peak | Cumulative DSM Savings (GWh) | As a % of 2012 forecasted load |
| 2013 | 1 | 0.1% | 9 | 0.1% |
| 2014 | 62 | 2.4% | 49 | 0.3% |
| 2015 | 131 | 5.1% | 131 | 0.8% |
| 2016 | 235 | 9.1% | 248 | 1.6% |
| 2017 | 263 | 10.2% | 413 | 2.7% |
| 2018 | 298 | 11.6% | 617 | 4.0% |
| 2019 | 332 | 12.9% | 817 | 5.3% |
| 2020 | 365 | 14.2% | 1,010 | 6.5% |
| 2021 | 397 | 15.4% | 1,199 | 7.8% |
| 2022 | 428 | 16.6% | 1,379 | 8.9% |
| 2023 | 458 | 17.8% | 1,550 | 10.0% |
| 2024 | 484 | 18.8% | 1,702 | 11.0% |
| 2025 | 508 | 19.7% | 1,839 | 11.9% |
| 2026 | 530 | 20.5% | 1,957 | 12.7% |

1

2 **Q: Please explain how you developed these data.**

3 A: As explained above, I began with an achievable energy efficiency savings potential of
4 1.2% per year on an energy basis. I then developed the projected savings based on several
5 factors, including the energy efficiency savings potential and the Company’s forecast and
6 claimed energy and capacity needs.

7 **Q: Did you assume that the Company could begin acquiring 1.2% savings per year**
8 **immediately?**

9 A: No. Consistent with typical efficiency program trajectories as described in the testimony
10 of Cathy Kunkel, I assume a ramp up period of five years, such that the Company is not
11 achieving the full 1.2% savings until 2018. This is a conservative ramp up rate. In reality,
12 new efficiency programs often experience a rush of program activity in early years due to
13 pent up demand, making it possible to achieve faster ramp up rates.

1 **Q: How do those assumptions translate into the data in the table above?**

2 A: From these assumptions, I developed an estimate of effective cumulative efficiency
3 savings (as a percentage of load) in each year from 2013 through 2036, taking into
4 account both incremental savings each year and the decay in savings from measures
5 reaching the end of their useful life. The percent savings in each year were applied to the
6 load forecast in that year to determine each year's efficiency savings in MWh. These are
7 reported in the table above.

8 **Q: The proposed Harrison plant acquisition is presented as meeting a capacity
9 deficiency in terms of generation capacity, or peak demand. Does your alternative
10 address this?**

11 A: Yes, to develop an estimate of peak reduction from my efficiency estimate I looked at the
12 ratio of kWh to kW savings in efficiency programs in nearby jurisdictions. In the end, we
13 use the average ratio from programs conducted by FirstEnergy Ohio, Duke Ohio,
14 Dominion Virginia, and in Massachusetts. These programs were focused more on annual
15 energy reduction, and therefore represent a conservative view of the potential peak
16 demand reductions from efficiency programs. As an aside, I note that if peak demand
17 reduction is an important objective for an efficiency portfolio, there are program designs
18 that can be used to increase peak reduction in proportion to energy reduction, such as
19 emphasizing programs that reduce cooling energy consumption and de-emphasizing
20 residential lighting programs, which generate relatively little peak savings. Furthermore,
21 peak reduction can be achieved using demand response programs specifically targeted at
22 that result.

1 **Q: Did you make any estimate of the potential for peak reduction from demand**
2 **response programs, and if so, will you please explain?**

3 A: Yes. Similar to the estimate of expanded energy efficiency, I reviewed studies of
4 available demand response resource to develop an estimate of the resource that is
5 available to provide peak demand reduction in West Virginia. Using information
6 presented in reports by published by the Federal Energy Regulatory Commission
7 (FERC)⁹ and the Brattle Group,¹⁰ I estimated an additional 96 MW of capacity available
8 from the residential and small commercial sectors from Direct Load Control (DLC). This
9 resource is not duplicative of currently realized demand response resources in the
10 Company's service territory, which are primarily realized from large commercial and
11 institutional customers and arranged by third-party aggregators or through customer's
12 direct participation in the PJM capacity markets.

13 **Q: Does your estimate represent an aggressive level of efficiency that may be difficult**
14 **or impossible to achieve?**

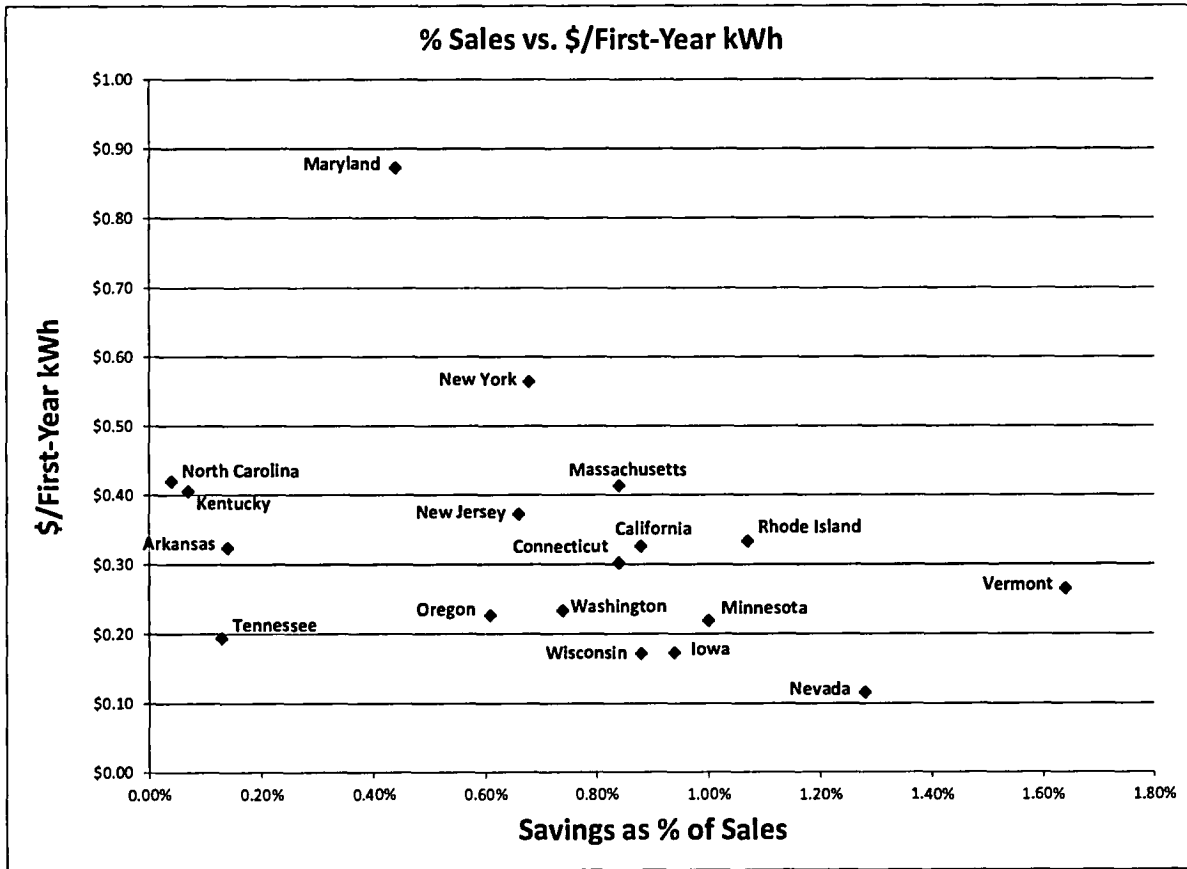
15 A: No, the strategies and policies that support this level of efficiency achievement are well-
16 studied and available for implementation in West Virginia. FirstEnergy itself already runs
17 efficiency programs in neighboring states that achieve greater levels of efficiency than
18 they have proposed for West Virginia.

19 **Q: What would be the cost of relying on efficiency and demand response for a greater**
20 **portion of the Company's load?**

⁹ See FERC, "A National Assessment of Demand Response Potential," <http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf>.

¹⁰ See The Brattle Group, "Direct Load Control of Residential Air Conditioners in Texas," http://www.brattle.com/_documents/UploadLibrary/Upload1093.pdf.

1 A: The cost would be low and would deliver lower total customer bills, resulting in
2 significant consumer savings. The West Virginia Potential Study referenced above also
3 estimates costs, based on actual program costs from other jurisdictions. For example,
4 2010 program data reported in the ACEEE 2012 Scorecard, an annual publication that
5 assesses empirical data of actual state energy efficiency program performance, shows that
6 many of the 13 top-performing states in energy efficiency (blue markers) are achieving
7 savings at costs between \$0.20 and \$0.40 per first-year kWh.¹¹



8

¹¹ ACEEE 2012 State Energy Efficiency Scorecard, <http://aceee.org/research-report/e12c>

1 In nearby jurisdictions, Maryland and Pennsylvania utilities spent on average \$0.23/first-
2 year kWh in 2010 and 2011. Data also indicate that efficiency savings are not getting
3 more expensive over time. A report prepared in 2006 that looked at over a dozen states
4 and utilities found an average first-year cost of \$0.213/kWh.¹²

5 As a conservative estimate, for efficiency savings I adopt the cost used in the
6 “Save Money” report of \$0.30/kWh. This is based on the un-weighted average of all cost
7 estimates from the ACEEE scorecard of top-performing states. This indicates an
8 efficiency investment of approximately \$356 million for the years 2013 through 2026 in
9 present value terms using the Company’s discount rate. Note that this investment will
10 generate energy savings and peak reduction, and therefore reduce customer energy bills,
11 for many years beyond 2026 without any additional cost; as discussed below, this savings
12 would total in excess of \$1 billion.

13 For the cost of demand response programs, we estimate the cost of both new
14 demand response installations and the on-going payments to participants. These were
15 developed from the same sources used to develop the estimate of demand response
16 capacity, plus an additional report published by the Natural Resources Defense Council.¹³
17 The additional cost of the demand response resource from 2013 through 2026 in present
18 value terms using the Company’s discount rate is \$47 million.

19 **Q: What benefits accrue to the Company’s ratepayers and customers as a result of this**
20 **spending?**

¹² Direct Testimony of Timothy Woolf before the Minnesota Office of Administrative Hearings, OAH No. 12-2500-17037-2, Exhibit JI-5-E.

¹³ See NRDC, “The Future of Demand Response: Connecting the Dots Between Smart Grid and Large Scale Wind Integration,”<http://www.maproyalty.com/downloads/the-future-of-demand-response.pdf>.

1 A: At the very least, customers who reduce their energy consumption as a result of
2 efficiency investments will see bill reductions on the order of \$1 billion over the 2013 to
3 2026 time frame, with further bill reductions continuing for several years after that as a
4 result of continued savings from efficiency measures installed through 2026 that continue
5 to generate savings over their entire useful lives. Furthermore, much of the spending on
6 DR goes directly to the program participants. Additional savings will accrue to both
7 participants and non-participants from Demand Reduction Induced Price Effects (DRIPE)
8 which I describe later in my testimony.

9 **Q: How does the cost of additional efficiency and demand response compare to the**
10 **costs for the proposed Harrison Plant?**

11 A: Efficiency is clearly cheaper. The \$0.30/kWh cost for efficiency only represents the first
12 year savings from an efficiency measure. Since a typical efficiency measure life is
13 between 6 and 20 years, the cost for each kWh saved over the lifetime only a fraction of
14 the first year cost. Depending on the measure, cost per lifetime kWh could range from 5
15 to 1.5 cents, although measures with shorter lifetimes are also typically less expensive, so
16 the typically average cost per lifetime of efficiency is on the order of 3 cents. The “Save
17 Money” report presents levelized cost estimates for efficiency ranging from 1.7 to 4 cents
18 per kWh. All of these estimates are lower than the proposed Harrison cost of 6.4
19 cents/kWh.

20 **IV: Efficiency provides additional benefits to West Virginia consumers and citizens**

21 **Q: Apart from cost considerations, are there other benefits for West Virginia**
22 **consumers that result from increasing efficiency investments?**

1 A: Yes, there are several additional benefits.

- 2 • Reducing economic risks posed by regulatory risk, fuel price volatility, and
3 load forecast errors – Acquiring the Harrison plant (or any other large, central
4 generating station) is an all-or-nothing proposition. Once the plant is
5 purchased, the Company’s ratepayers are committed to paying for its entire
6 cost and operation. This is true whether or not the load it purports to serve
7 materializes and regardless of the price of natural gas, coal or any
8 environmental control or compliance costs that may come into effect in the
9 future. With the exception of commodity prices for coal and gas, the Company
10 did not test the sensitivity of its analysis to these possible futures. Regardless,
11 these analyses are of limited diagnostic value, because none of them look at
12 expanded levels of efficiency and demand response. In contrast, energy
13 efficiency and demand response resources can be developed and deployed
14 incrementally to match actual conditions. This trades a large risk (i.e., a large
15 revenue requirement over a long period of time for a un-necessary or un-
16 economic capital investment) for a smaller one (i.e., the potential need to
17 acquire resources through market purchases or other shorter lead-time supply-
18 resources for a short period of time until additional resources can be
19 developed, whether through additional demand side resources or facilities
20 such as Harrison).
- 21 • Promoting local jobs and spending - Investments in energy efficiency create
22 jobs directly through the implementation of efficiency upgrades to buildings

1 and equipment and indirectly through subsequent spending of both job income
2 and bill savings from reduced energy consumption. In comparing efficiency
3 and renewable energy investments with the purchase of existing central station
4 generation like the Harrison plant, it is important to note that none of the large
5 capital investment will create construction jobs in West Virginia: Harrison is
6 already built. Furthermore, a large fraction of the costs of operating the
7 Harrison Plant will be for coal. Even though the coal is mined in West
8 Virginia, the majority of the costs of coal are for the value of the commodity
9 itself, as opposed the labor needed to mine the coal and bring it to market.
10 More importantly, the Harrison plant's continued operation in West Virginia
11 hinges not at all on whether or not FirstEnergy acquires the remaining
12 ownership stake. No additional employment or spending will be attributed to
13 the acquisition. On the other hand, because the costs of efficiency investments
14 are limited largely to equipment and installation labor and because all of these
15 dollars represent new spending within West Virginia, more of the dollars
16 spent on efficiency will directly benefit the West Virginia economy and its
17 workers.

- 18 • **Reducing the need for transmission and distribution upgrades - By slowing**
19 load growth or even eliminating it in targeted areas, efficiency generates
20 additional benefits that may not be reflected in current avoided cost estimates
21 based on current energy market prices.

- 1 • Demand Reduction Induced Price Effects – The reduced energy demand due
2 to efficiency programs allows for the shedding of the most expensive
3 resources on the margin, thus lowering the overall cost of energy. This is
4 referred to as Demand Reduction Induced Price Effects (DRIPE). In New
5 England, where efficiency has made substantial reductions in load growth, this
6 effect has been estimated and is included in cost-effectiveness tests as an
7 additional benefit. A recently-released report from the Ohio Manufacturer’s
8 Association notes the importance of this effect in Ohio, where the price
9 mitigation resulting from full implementation of that state’s energy efficiency
10 resource standard through 2020 represent could total over \$2 billion, or a 60%
11 increase in benefits above the already cost-effective wholesale energy savings
12 resulting from that policy.¹⁴ Even if the effect is smaller and goes un-assessed
13 in West Virginia, it represents another benefit of efficiency over traditional
14 supply-side options.
- 15 • Increasing efficiency program participation means fewer non-participants and
16 greater equity – As I discuss later, distributional equity can potentially be a
17 concern with efficiency programs. Ideally all FirstEnergy customers would
18 have the opportunity to lower their bills through participation in efficiency
19 programs. Greater levels of investment in efficiency programs make it more

¹⁴ Neubauer, M, et al. *Ohio’s Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State*. ACEEE Report Number E138, April 2013.
http://www.ohiomfg.com/communities/energy/OMA-ACEEE_Study_Ohio_Energy_Efficiency_Standard.pdf

1 feasible for all customers to participate at some level and minimizes the
2 number of non-participants who may see bill increases as a result.

3 **Q: With respect to your mention of the job impacts from spending on efficiency and**
4 **demand response, can you provide any estimate of the potential job impacts?**

5 A: Yes. As detailed in the “Save Money” report I referenced earlier, estimates of job
6 creation from spending on efficiency investments ranges from 43 to 250 jobs per million
7 dollars invested in efficiency. Again adopting the value used in that analysis (54.7 jobs
8 per million dollars), the job impacts from the efficiency investments I described earlier
9 reach nearly 2,000 jobs in 2016 and over 3,400 jobs from 2018 onwards. Importantly,
10 most of this job creation would be located in West Virginia, as efficiency spending is
11 composed largely of local labor (contractors, engineers, program staff, etc) and products
12 typically purchased from local retailers and distributors. Furthermore, these estimates do
13 not include any assessment of the job creation resulting from the demand response
14 spending included in my analysis, which would also require local labor for equipment
15 installation.

16 **Q: What drawbacks have been identified about relying on efficiency for a greater share**
17 **of load?**

18 A: Much of the concern is focused on the costs of efficiency, particularly the issue of the
19 potential distributional effects from rate increases that result from reduced energy sales.

20 **Q: Do you share these concerns?**

21 A: Only to a limited extent. While it is true that energy efficiency programs will slightly
22 raise both rates and bills for some customers who choose not to participate in the

1 programs, approving the Harrison acquisition will result in rate increases for ALL of
2 FirstEnergy's customers, none of whom will have a choice as to their participation in this
3 investment. I understand that taking an action that raises customers' energy bills should
4 not be undertaken lightly and requires careful consideration of distributional effects.
5 Nevertheless, it is important to point out that it is misleading to only consider these
6 effects as they might result from efficiency. The choice is not between doing efficiency
7 and doing nothing. As clearly indicated by this case, the choice presented is between
8 committing well over one billion dollars of ratepayer funds to acquire Harrison (and
9 billions more for the energy generated over its life) and investing in resources with lower
10 total costs for West Virginia's ratepayers. The latter course better protects the public.

11 **V: FirstEnergy's criticisms of EE are unfounded**

12 **Q: The Company has indicated that demand response and energy efficiency programs**
13 **are not practical solutions for meeting its capacity shortfall, given the magnitude of**
14 **the deficit. Do you agree with this statement?**

15 **A:** No. While savings achieved through demand response and energy efficiency programs
16 may not be able to cover the entirety of the shortfall the company predicts, they would
17 cover one-third of the energy and capacity needs by 2026. Whatever remains of the
18 company's forecasted deficit could be made up by market purchases, smaller fossil-fired
19 units, renewable resources, or other supply-side resources, or some combination of these.
20 Since efficiency is the least cost resource available, a portfolio of technologies including
21 efficiency, demand response, and market purchases would be cheaper overall than the
22 Harrison acquisition, even if an individual component of the portfolio is more expensive.

1 Indeed, Sierra Club Witness David Schlissel demonstrates this in his testimony submitted
2 in this proceeding. Further, this portfolio approach would allow for much greater
3 diversification of fuel sources as well as a much more adjustable ramp up in capacity,
4 thus protecting ratepayers from unexpected increases in resource prices or demand that
5 falls short of forecasts.

6 It is critical to keep in mind, moreover, that the issue presented by the Company's
7 proposal is not one of *reliability*—Harrison's operation and supply of power to the grid is
8 not in question. Instead, the issue is one of mitigating risks to consumers. Steady annual
9 investment in energy efficiency is a far better method of mitigating consumer risk than is
10 the massive all-at-once, all-or-nothing investment in a fixed resource that the Company
11 proposes.

12 **Q: With respect to forecast demand, do you have an opinion about the Company's forecast**
13 **demand growth?**

14 A: Yes, I believe that the load forecast may be overstated because it is greater than recent results
15 suggest, particularly in the near-term. The Company's 2012 Resource Plan explains that
16 the Company developed a load forecast using an average annual growth rate in energy of
17 1.4% and of peak demand of 1.2% (Filing, Exhibit A, p. 2) for the planning period,
18 through 2028. However, the Company assumes a much higher growth rate in the near
19 term. The data presented in Figures 1 and 2 in the Resource Plan show a compound
20 annual growth rate from 2013 through 2017 of 2.0% in energy and 1.7% in peak demand.
21 Furthermore, both the near-term and the long-term energy growth rates forecast by the
22 Company exceed historical experience. The Company provided annual load data in a

1 response to West Virginia Citizen Action Group (WVCAG)'s Second Request for
2 Information Q-15.¹⁵ These data demonstrate a compound annual growth rate of just 1.2%
3 per year from 1999 through 2012, and just 0.3% over the past 8 years, since 2004. This
4 means that the Company's forecast growth rate in the near term is nearly 7 times the rate
5 that actually occurred in the past 8 years. It seems that the Company's forecasts therefore
6 may well overstate any capacity shortfall, particularly in the near-term, and accordingly
7 may overstate the need for additional capacity.

8 **Q: And if the Company's has overstated the need for additional capacity, what would be**
9 **the effect on your analysis of efficiency and demand response?**

10 A: At the very least, it would mean that the demand side resources I identified earlier would
11 address a larger portion of the Company's projected shortfall in energy and peak
12 capacity.

13 **Q: In its filing, the Company stresses the importance of "planning flexibility, the**
14 **creation of an optimum asset mix, risk adaptability, and long-term environmental**
15 **compliance planning." Do you believe that the Harrison acquisition furthers these**
16 **goals?**

17 A: No. With regards to planning flexibility, the Harrison plant is an all or nothing deal, and
18 if expected load growth fails to materialize ratepayers are still stuck paying for the
19 acquisition. Further, the Harrison plant alone makes up almost two thirds of expected
20 2014 energy (GWh) sales, and the net transaction results in energy resources 37% higher

¹⁵ This response is included herein as Exhibit ER-JML-4.

1 than expected load in 2014 and 20% higher than expected 2026 load.¹⁶ There is no
2 guarantee that the Company will be able to sell such significant overcapacity into the
3 market at rates high enough to recover Harrison's fixed and variable costs. According to
4 the Resource Plan provided as Exhibit A to FirstEnergy's initial filing, Harrison energy
5 costs 50% more than recent average market prices (\$64/MWh vs. \$42.52/MWh).¹⁷ The
6 transaction in effect replaces ratepayer risk that market prices will rise significantly faster
7 than coal prices with ratepayer risk that market prices will stay low.

8 The Harrison plant would also increase the Company's already large exposure to
9 coal. Overreliance on any single asset class increases future risk, as the cost of electricity
10 is then highly correlated to the price of energy from that asset class. Further, any future
11 environmental regulations between now and 2026 are highly likely to implicate coal fired
12 plants, so the acquisition of a large coal plant drastically increases risk from potential
13 environmental compliance costs over and above any other asset class. Efficiency and
14 demand response, by contrast, will not be impacted by future environmental regulations,
15 and will protect ratepayers from price swings in coal and other commodities.

16 **Q: The Company claims that "DR contracts issued through state-required programs**
17 **can result in, and have resulted in, higher costs to customers." Please describe your**
18 **assessment of the impact of DR programs on costs to customers.**

19 **A:** Customers participating in DR programs experience reduced electricity bills and
20 incentive payments from adjusting their loads in response to current supply costs or other
21 signals. Other customers also receive cost benefits as a result of DR Programs. DR

¹⁶ Based on data provided in Section 8.3.6.3 of Exhibit A to the Company's filing, adjusted to remove the contributions of OVEC, as per page 7 of the Filing.

¹⁷ Recent market price from Exhibit A, page 13, Figure 6.

1 programs reduce the need to run expensive power plants during periods of peak demand,
2 which reduces production costs and prices for wholesale electricity buyers. In the long
3 run, demand response helps to lower system capacity requirement which prevents
4 retailers from having to buy or build additional capacity. These cost savings are
5 eventually passed onto all retail customers in the form of bill savings. Over the longer
6 term, sustained demand response lowers aggregate system capacity requirements,
7 allowing load-serving entities (utilities and other retail suppliers) to purchase or build less
8 new capacity. Eventually these savings are passed onto retail customers as bill savings.
9 As one specific example, Baltimore Gas and Electric Company estimates the capital cost
10 of DR at \$165/kW,¹⁸ compared to the Company's calculated Harrison costs of \$401/kW
11 and the Company's own estimate of the cost of new combined cycle generation of
12 \$656/kW. At less than half the cost of the cheapest supply side options, demand response
13 programs are clearly beneficial for participants and non-participants alike.

14 **Q: The Company has indicated that EE resources are not dispatchable, cannot be**
15 **metered, and have uncertain long-term persistence. Do you agree with this**
16 **statement?**

17 **A:** While it is true that energy efficiency resources are not dispatchable, this is irrelevant to
18 the desirability of efficiency programs: EE resources represent *permanent* (at least, over
19 their useful life) reductions in energy use and peak demand. They need not be
20 dispatchable to provide reliable system resources. Demand response programs, on the
21 other hand, can serve as dispatchable resources that provide additional benefits to an

¹⁸ Hesser, Theodore Gates. *The Future of Demand Response*. September 2010.
<http://www.maproyalty.com/downloads/the-future-of-demand-response.pdf>.

1 overall DSM portfolio. With regards to whether or not efficiency resources can be
2 metered, the Company's contention is plainly untrue. The savings from specific
3 efficiency projects can be measured with a high degree of certainty through metering
4 protocols such as those contained in widely-accepted frameworks such as the
5 International Performance Measurement and Verification Protocol (IPMVP).

6 Frameworks such as the IPMVP also provide protocols for non-meter based
7 methods for assuring the reliability and veracity of energy savings estimates. As an
8 example of the trust put in these estimates, Energy Service Companies (ESCOs) do a
9 thriving business in providing guaranteed savings to their customers, for which customers
10 pay billions of dollars each year.¹⁹ Clearly, businesses will not pay for savings that are
11 not verifiable. When it comes to efficiency programs and portfolios, a comprehensive and
12 robust practice of evaluation, measurement, and verification (EM&V) processes has been
13 developed to support trust and confidence in the savings resulting from efficiency
14 programs.

15 **Q: What about persistence? Can efficiency measures be expected to remain in place**
16 **and operational as long as the equipment lasts?**

17 **A:** Yes, they can. As long as West Virginia uses expected useful life (EUL) assumptions that
18 have already been developed to take into account the fact that some people may remove
19 the measure early, measure persistence will not be an issue. This subject has been
20 evaluated in detail in other jurisdictions, and estimates of efficiency potential are based
21 on measured data on the EUL of each measure. The EUL is defined as the median

¹⁹ Satchwell, A. et al, *A Survey of the U.S. ESCO Industry*. Published by Lawrence Berkeley National Laboratory, June 2010. LBNL-3479E.

1 number of years that a measure is likely to remain in place and operable; it therefore
2 takes into consideration the likely persistence of the measure. Thus, the most common
3 definition of measure life already takes into account business turnover, early retirement
4 of installed equipment or other reason measures may be removed or discontinued.
5 Further, different and independent studies of EUL have found similar lifetimes for similar
6 measures, lending confidence to industry estimates.²⁰

7 **Q: Ok, but how do you know that the customer would not have installed the measure**
8 **sometime in the future, even without the utility EE program?**

9 **A:** This situation is typically accounted for in the evaluation of the efficiency programs.
10 These evaluations look at freeriders, people who use the program rebate to buy a product
11 they would have bought at the same time without the program, as well as partial
12 freeriders, who were planning on buying the product at a later date but bought it earlier
13 due to the existence of the rebate program. The net freeridership rate is used to adjust the
14 savings downwards to ensure that only savings directly caused by program activity are
15 claimed.

16 It is important to note that there is a complementary phenomenon to freeridership
17 known as spillover. Spillover occurs when purchasing decisions are influenced by the
18 efficiency program, but where the customer does not become a program participant (for
19 example, by not claiming an available rebate). This influence could be caused by, for
20 example, increased awareness and stocking of efficient equipment as a result of the
21 efficiency program. Spillover acts to offset the decrease in net savings from freeridership

²⁰ Skumatz, Lisa. *Lessons Learned and Next Steps in Energy Efficiency Measurement and Attribution: Persistence of Energy Efficiency Behavior*. November 2009.
http://rtf.nwcouncil.org/subcommittees/measurelife/MeasureLifetimeExcerptSkumatz_CIEE_v10.pdf.

1 but can be harder to measure. In some cases, it is ignored or only addressed over longer
2 time-scales through studies that look for shifts in overall customer purchasing behavior.
3 Regardless, it is a very real effect of efficiency programs.

4 **Q: If efficiency is cost-effective for the consumer, why is a utility program necessary?**
5 **Shouldn't consumers make those investments on their own?**

6 **A:** There are numerous market barriers that prevent people from investing in efficiency
7 despite the favorable economics. These barriers include:

- 8 • High first cost - An efficiency measure typically involves paying more money upfront
9 in exchange for savings that are spread out over 5-20 years. Individuals may not be
10 able to afford the higher upfront costs of efficient equipment, and businesses may
11 have procurement policies that require purchasing the item with the lowest first cost.
- 12 • Split incentives – In many cases, the entity responsible for energy payments is not the
13 entity responsible for making capital improvements. This is common in building
14 rentals where the building owner makes capital investments and the renter pays the
15 energy bills. The owner has little incentive to pay more money for efficient
16 equipment when he or she does not see any of the resulting savings.
- 17 • Imperfect information – Energy costs are often a low priority for busy people and
18 businesses, and the market for energy efficiency is highly fragmented, with many
19 technologies and actors. This makes it hard and time-consuming for typical people to
20 separate hype from reality, recognize efficiency potential in their buildings, and gain
21 confidence in the resulting savings.

1 A good efficiency program administrator seeks to understand the specific market barriers
2 that are preventing efficiency investment and designs the EE programs to explicitly
3 address each barrier.

4 **Q: The Company suggests that DR Resources are not under its control and**
5 **curtailments are in the hands of the customers, not the utility. Are there ways to**
6 **overcome this challenge?**

7 A: First, it is not true that all DR resources are not within the control of the utility. DR
8 program designs can provide utilities with greater control over demand response
9 resources by utilizing direct load control (DLC). Under DLC programs, customer
10 participation is voluntary, but load control event participation is not. DLC programs have
11 a proven track record of achieving significant savings. A survey of the countries' largest
12 residential and small C&I DLC programs finds feasible participation rates of at least 10-
13 30%, demand reduction of between 0.8 and 1.5 kW per participating home, and between
14 2 and 4 kW for small C&I participants.²¹ Participation in these direct load control
15 programs is dependent on an agreement to allow the utility to cycle the air conditioner or
16 lower the setpoint during certain high load events. This puts the DR resources quite
17 clearly in the hands of the utility.

18 Second, for DR programs that rely on voluntary responses to price or other signals,
19 program evaluation and experience can indicate the behavior that will result *on average*
20 from event calls, which allows the utility to have confidence in projected load reductions

²¹ The Brattle Group. *Direct Load Control of Residential Air Conditioners in Texas*. October 25, 2012, http://www.brattle.com/_documents/UploadLibrary/Upload1093.pdf.

1 in aggregate, even if they are unable to determine in advance whether or not a particular
2 customer will respond to a particular event.

3 **Q: The Company states that it is reluctant to pursue DR, since PJM rules concerning**
4 **DR have changed in the past, and will likely continue to change. How can possible**
5 **future changes in PJM rules impact the desirability of DR?**

6 **A:** This statement does not seem applicable to the discussion at hand. A level of uncertainty
7 and the threat of changing economic and regulatory conditions exist regardless of the
8 capacity resource being considered. While the Company's statement may be accurate, it
9 does not describe a weakness of DSM as a resource that is absent from consideration of
10 other generation resources. Clearly environmental regulations, financial conditions,
11 market conditions and other factors are constantly in flux, affecting all aspects of a
12 utility's operation. In anything, the fact that the future is uncertain tilts the assessment in
13 favor of resources that can be deployed incrementally, quickly, and flexibly. Purchasing
14 over 1,000 MW of coal-fired generation at one time does not fit those criteria.

15 **Q: Does this conclude your testimony?**

16 **A:** Yes, it does.

**Direct Testimony of Jeffrey Loiter
on behalf of
The Sierra Club
before the
Public Service Commission of West Virginia
Case No. 12-1655-E-PC**

1 **I: Introduction**

2 **Q. Please state your name and business address.**

3 A. My name is Jeffrey Loiter and my business address is Optimal Energy, Incorporated, 14
4 School Street, Bristol, VT 05443.

5 **Q. On whose behalf are you testifying?**

6 A. I am testifying on behalf of the Sierra Club.

7 **Q. Mr. Loiter, by whom are you employed and in what capacity?**

8 A. I am employed as a Managing Consultant by Optimal Energy, Inc, a consultancy
9 specializing in energy efficiency and utility planning. In this capacity, I direct and
10 perform analyses, author reports and presentations, manage staff, and interact with clients
11 to serve their consulting needs. My clients include NGOs, state energy offices and
12 efficiency councils, utilities and third-party program administrators. For example, I
13 participate on the consultant team supporting the work of the Massachusetts Energy
14 Efficiency Advisory Council.

15 **Q. Please summarize your work experience and educational background.**

16 A. I have 15 years of experience in environmental and economic consulting. For the past
17 five years, I have been engaged in a variety of work at Optimal Energy related to energy
18 efficiency program design and analysis. For example, I prepared two documents for
19 inclusion in EPA's *National Action Plan for Energy Efficiency (NAPEE)*: a guidebook on

*Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
West Virginia PSC Case No. 12-1655-E-PC
June 18, 2013*

1 conducting efficiency potential studies, and a handbook describing the funding and
2 administration of clean energy funds.¹

3 In my capacity as a Managing Consultant at Optimal, I also advise clients on
4 efficiency program design and implementation. For example, I recently contributed to a
5 5-year Energy Efficiency and Demand Response Plan for the Tennessee Valley
6 Authority. I have also participated in several studies of efficiency potential and
7 economics, including ones in New York, Vermont, Texas, Massachusetts, and Prince
8 Edward Island. These studies have ranged from macro-level assessments to extremely
9 detailed, bottom-up assessments evaluating thousands of energy efficiency measures
10 among numerous market segments.

11 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
12 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
13 Environmental Engineering from Cornell University and an *M.S.* in Technology and
14 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
15 ER-JML-1.

16 **Q. Have you previously testified before the Public Service Commission of West**
17 **Virginia (“the Commission” or “PSC”)?**

18 **A.** Yes, I recently testified in Case No. 12-1571-E-PC regarding FirstEnergy’s request for an
19 asset transfer related to the Harrison plant.

20 **Q: What is the purpose of your testimony in this proceeding?**

¹ These documents can be found at http://www.epa.gov/cleanenergy/documents/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

*Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
West Virginia PSC Case No. 12-1655-E-PC
June 18, 2013*

1 A: The purpose of my testimony is to comment on the Company's petition for approval of a
2 generation resource transaction and related relief, predominantly concerning the Amos
3 and Mitchell Power Stations.

4 **Q. Are you submitting exhibits along with your testimony?**

5 A. Yes. I have attached my resume as an Exhibit ER-JML-1. In addition, I have attached the
6 following.

7 - Exhibit SC-JML-2: Gunn, R. and M. Thornsjo, "Appalachian Power Co – West
8 Virginia; 2009-2028 DMS Potential Study," Summit Blue Consulting, LLC, November
9 12, 2009.

10 - Exhibit SC-JML-3: Optimal Energy, "Save Money, Create Jobs: How Energy
11 Efficiency Can Work for West Virginia."

12 - Exhibit SC-JML-4: Joint Comments of the American Council for an Energy Efficiency
13 Economy, the Alliance to Save Energy, the Natural Resources Defense Council and
14 Energy Center of Wisconsin on the January 2009 Report: "Assessment of Achievable
15 Potential from Energy Efficiency and Demand Response Programs in the U.S." issued
16 by EPRI.

17 **II: Summary of Conclusions**

18 **Q: Have you reviewed the Company's filing in this matter?**

19 A: Yes, I have review the Company's filing.

20 **Q: Please summarize your conclusions.**

21 A: Based on my review of the filing and a substantial body of other evidence, I have four
22 major conclusions.

- 1 • First, demand side resources were not sufficiently examined as a potential
- 2 resource in Appalachian Power’s Comparative Analysis of Resource Portfolios.
- 3 • Second, that the company’s load forecast and analysis lack the details necessary
- 4 to corroborate that the proposed acquisitions are indeed the best options for
- 5 ratepayers.
- 6 • Third, that significant additional demand side resources, both energy efficiency
- 7 and demand response, are available to offset traditional supply side resources such
- 8 as those represented by the Amos and Mitchell acquisitions.
- 9 • Finally, greater investment in demand side resources and energy efficiency in
- 10 particular would provide West Virginia ratepayers and consumers with significant
- 11 additional benefits beyond immediate savings on their electric bills, in the form of
- 12 mitigating fuel price risks, promoting local jobs and spending, reducing the need
- 13 for transmission and distribution upgrades, and general reduced price effects, as
- 14 explained in more detail below.

15 I believe that realizing the available energy efficiency potential in the Company’s service
16 area would save ratepayers over \$1.2 billion through 2026 and would in the process
17 create over 6,000 jobs for much of the time between now and then.

18 **III: APCo’s analysis of alternative resource portfolios is incomplete and insufficient**

19 **Q: In the materials filed in support of their petition for the Amos and Mitchell**
20 **acquisitions, did the Company consider strategies other than the proposed plants**
21 **for meeting their load requirement?**

- 1 A: Yes, in this filing the Company compared the proposed Amos and Mitchell plant
2 acquisitions with five other supply-side options:
- 3 1. Reliance on the PJM market through 2025
 - 4 2. Reliance on the PJM market through 2017, with a model optimized portfolio
5 thereafter
 - 6 3. The proposed transfer (Mitchell and Amos 3)
 - 7 4. Only the Amos 3 transfer, without the Mitchell transfer
 - 8 5. Only the Mitchell transfer, without the Amos 3 transfer

9 The scope of this analysis is very limited, in that the only alternatives to the proposal
10 examined were essentially increased market purchases and only performing part of the
11 transfer. Options such as long-term PPAs, new supply, or increased demand side
12 resources were not considered at all.

13 **Q: Did the analysis examine costs related to environmental compliance?**

14 A: The analysis includes compliance costs associated with current regulations, and a very
15 small carbon tax of \$12 starting in 2020, declining from there. These were held constant
16 across all three pricing scenarios in the analysis; no sensitivity analysis was performed to
17 examine the results in the event of higher than expected compliance costs or carbon tax.
18 Given that the analysis looks more than a decade into the future, environmental costs
19 could be significantly higher than forecasted by APCo, and the lack of any attention to
20 this risk introduces significant uncertainty into the analysis.

21 **Q: Did the Company compare the proposed plant acquisitions with any demand-side
22 resources such as energy efficiency or demand response?**

1 A: No, demand-side resources were not seriously considered in evaluating alternatives to the
2 acquisitions. The “Comparative Analysis of Resource Portfolios” submitted as Exhibit A
3 to the petition included a limited amount of efficiency and demand response which was
4 held constant across all of alternate portfolios. No analysis was conducted of the potential
5 for efficiency or other demand-side resources to defer or eliminate the need for the plants,
6 nor were increased demand-side resources examined in conjunction with other supply-
7 side options as a potential portfolio alternate to the planned acquisition.

8 **Q: Is it appropriate to exclude efficiency and demand response from power planning?**

9 A: No. Decades of experience from across the country have proven EE and DR to be reliable
10 low-cost resources. In order to ensure ratepayers are getting the lowest-cost power
11 available, it is necessary to analyze DR and EE as alternatives or complements to supply
12 side resources.

13 **Q: Did the Company at least include planned efficiency efforts in their projected**
14 **capacity shortfall?**

15 A: The company did include the results of existing and “expected new” DSM reductions, as
16 shown in Figure 1-2 of Appendix 1 of Exhibit A to its application.

17 **Q How much DSM did the Company include in their analysis?**

18 A: Unfortunately, it is difficult to determine exactly how much DSM the Company included.
19 The text of Exhibit A to the filing, for example, claims a 3.3% reduction in energy usage
20 by 2022 and a 5.5 percent demand response capability, citing to a 2009 EPRI study
21 (Exhibit A, p. 10 of 25). However, Figure 1-2 in that same Exhibit indicates only a 1.5%
22 contribution from “conservation/efficiency” in 2022. While this figure is based on the

1 Company's capacity position, rather than energy, the greater than two-fold difference
2 between a 3.3% reduction in energy and 1.5% reduction in demand is not explained
3 anywhere in the filing. To a lesser extent, the same problem exists with demand response.
4 Figure 1-2 indicate a 4.8% reduction from demand response, including both existing and
5 "expected new," but this is less than the 5.5% claimed in the text. In addition, the text
6 also cites to additional savings from a Volt VAR Optimization initiative of 190 GWh and
7 35 MW of reductions, although no timeline is given for achieving these levels.

8 **Q: Did you attempt to reconcile these discrepancies?**

9 A: Yes. I reviewed other sources, including responses to discovery requests from WVCAG's
10 first and second set of requests for Case 11-1775-E-PC and the Consumer Advocate
11 Division's (CAD) first and second set of requests for this case, but was unable to
12 reconcile the differences. For example, the Company's response to CAD Set 2 DSM 1,
13 Attachment 9, appears to note a total energy reduction of 911 GWh in 2022, which
14 represents 2.7% of forecast load in that year. This is troubling, because this inconsistency
15 serves to undermine one's confidence in the analysis as a whole.

16 **Q: Returning to the reported level of efficiency in the filing, can you explain the source
17 of the Companies' estimates?**

18 A: With respect to the 3.3% energy reduction number noted in the text of Exhibit A, the
19 Company cites a 2009 EPRI study titled "Assessment of Achievable Potential from
20 Energy Efficiency and Demand Response Programs in the US." An Excel workbook
21 provided in response to CAD Set 1 IRP 03 includes this value as the energy savings
22 achievable in 10 years for a "realistically achievable" scenario using incentives equal to

1 50% of measure costs. Nevertheless, my review of the EPRI study finds that the reported
2 10-year realistic achievable potential is 4.8% on a national basis, with regional results
3 ranging from 4.4% to 5.7%.

4 **Q: How do the EPRI estimates compare with estimates from other studies across the**
5 **country and the region?**

6 A: The EPRI estimates for efficiency are much lower than those of comparable studies. For
7 example, a 2009 McKinsey report entitled “Unlocking Energy Efficiency in the US
8 economy” estimates enough cost-effective energy efficiency to make up roughly 25% of
9 sales by 2020.² The EPRI study, by contrast, estimates a maximum achievable potential
10 of 11.2% nationally, and over a period of 20 years rather than 10. Further, a study
11 commissioned by Appalachian Power itself found a realistically achievable efficiency
12 potential of 20% over 20 years (Exhibit SC-JML-2). The study, completed by Summit
13 Blue consultants (now Navigant), relied on West Virginia specific inputs, yet the results
14 appear to have been completely ignored by APCo in the analysis of resource alternatives
15 in favor of the EPRI study that is not specific to West Virginia and that produces results
16 that are low end outliers to the existing body of potential studies. Note that the achievable
17 efficiency results from the Summit Blue study represent 6 times greater efficiency than
18 the 3.3% cited to EPRI in the filing, and more than 10 times greater than the level
19 represented in Figure 1-2 of Attachment A.

20 **Q: Why might the EPRI estimates be overly conservative?**

²www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy

1 A: There are many reasons to think that the EPRI study gives a significant underestimate of
2 the potential for efficiency. A group of organizations including the American Council for
3 an Energy Efficient Economy, the Alliance to Save Energy, the Natural Resources
4 Defense Council and the Energy Center of Wisconsin released joint comments critiquing
5 the study. Key points include:

- 6 • The study assumes programs do not induce early replacement of equipment
7 before the end of its useful life (so-called “retrofit” measures)
- 8 • The study only looks at technologies that have already been fully
9 commercialized and that are widely available
- 10 • The study only looks at ‘widget’ based approaches (i.e., changing out a piece
11 of equipment for a similar but higher-efficiency piece of equipment on a one-
12 to-one basis), and fails to take into account the significant additional savings
13 available from taking a comprehensive, systems based approach to efficiency.
- 14 • The study does not include the potential impact of new codes, standards, or
15 regulatory policies.
- 16 • Assumed program design and penetrations did not take into account current
17 best practices.

18 The full text of the comments prepared by the above-noted organizations is provided as
19 Exhibit SC-JML-4.

20 **Q: What cost assumptions does Appalachian Power use for its efficiency programs, and**
21 **do you think this is an accurate reflection of likely costs?**

1 A: Based on information presented in the response to CAD Set 1 IRP 03, the Company
2 appears to assume a first year cost of approximately \$0.73 per first-year kWh. I believe
3 that this is an overestimate for a few reasons:

- 4 1. First, this is far more expensive than recent results from APCo's efficiency
5 programs. According to data provided in response to CAD Set 2 DSM 1, the
6 Company's programs generated energy savings at \$0.13 per first-year kWh in
7 2011 and just \$0.09 per first-year/kWh in 2012.
- 8 2. Second, much of the cost data are sourced as coming from the California
9 Database for Energy Efficient Resources (DEER) from 2008 and RSMMeans data
10 from 2007. The cost of efficient equipment typically falls fairly rapidly as it gains
11 wider acceptance in the market place. Therefore, the cost delta between standard
12 and efficient equipment today is going to be significantly lower than it was 6
13 years ago.
- 14 3. Third, I notice that in many cases the Company includes labor costs for market
15 driven measures. Market driven measures occur when an existing piece of
16 equipment fails and needs to be replaced anyway. Therefore, the cost of the
17 measure is not the total cost of the equipment and the installation, but only the
18 difference between the cost of the efficient equipment above the cost of the
19 standard equipment. Since labor costs are incurred during the installation of the
20 standard equipment, they should not be included as an "efficiency cost." Even if
21 the Company is assuming that measures whose total cost includes an installation
22 cost are in fact early retirements or "retrofits," this is in conflict with the

1 Company's reliance on the EPRI potential study, which explicitly EXCLUDES
2 early retirement measures.

3 4. Fourth, total program costs were derived by looking at a block of technologies, all
4 with varying costs, and taking the median cost of the block. In reality, there will
5 likely be more program participation in the less expensive measures than the more
6 expensive measures, so actual costs are more likely to be in the low end of the
7 costs of the block, rather than the straight median.

8 **Q: Did the Company conduct an analysis to determine the least-cost means of meeting**
9 **its purported PJM capacity and energy requirements?**

10 A: No, it did not. As clearly stated by Company Witness Torpey, the Company only looked
11 at the relative costs of the alternative resource options that they present in the filing,
12 which clearly do not represent the entire universe of possible strategies and approaches
13 for meeting the their purported needs: "It is also critical to understand that the framework
14 for these evaluations was focused not on the absolute CPW results, but rather a
15 comparative view of the alternative options' results." [p. 9]. The Company is not asking
16 for approval of the least-cost means of meeting their load; it is seeking approval instead
17 for the least-cost means among those that it has chosen to present to the Commission.

18 **IV: The Company has not clearly demonstrated the purported need for the asset**
19 **transfer**

20 **Q: What is the Company's stated basis for the proposed asset transfer?**

21 A: The Company states that it needs to procure additional resources to enable it to satisfy its
22 capacity requirements to PJM and to "provide baseload generation to meet its customers'

1 energy requirements.” (Petition, p. 2). The first of these, capacity requirements, is
2 typically expressed in terms of peak capacity measured in units of megawatts (MW). The
3 second, energy requirements, is usually expressed in terms of annual energy production
4 and sales in units of megawatt-hours (MWh).

5 **Q: Does the Company provide data or analysis to support the stated need?**

6 A: No, the Company has only addressed the first of these assertions regarding capacity
7 requirements. The Company has failed to provide any data or information regarding the
8 sufficiency of its portfolio to meet its customers’ energy requirements. No information on
9 the expected annual energy shortfall nor on the expected annual generation from the
10 proposed assets is provided.

11 **Q: What is the consequence of this failure to consider the energy-side of the Company’s**
12 **requirements?**

13 A: Because energy use is not distributed evenly in time, utilities require capacity to meet
14 peak loads that occur for a very short duration each year. These short-term needs are
15 typically met through the use of “peaker” plants that are only run at times of high
16 demand. Often these are simple gas combustion turbines that are inexpensive to install
17 but more expensive to run than larger baseload facilities like the Amos and Mitchell
18 plants. The baseload facilities exist to provide large quantities of energy throughout the
19 year to meet energy requirements. The Company is stating that they have a need for
20 energy (in addition to capacity) and are proposing to acquire assets that are suited to
21 meeting baseload energy requirements, yet they have not provided any analysis to
22 demonstrate a match between those needs and the output of the proposed assets. On the

1 other hand, the Company has made much of the capacity shortfall it faces, yet has not
2 analyzed any resources that specifically address capacity needs beyond a small amount of
3 demand response.

4 **V: Demand side resources could offset much of APCo's medium-term capacity
5 shortage**

6 **Q: Given your criticisms of the Company's approach to addressing DSM in their
7 analysis of potential alternatives to the proposed asset transfer, have you made an
8 estimate of the DSM resource available in APCo's service territory?**

9 A: Yes, I have. I believe that APCo's efficiency programs could be ramped up to achieve
10 annual saving of 1.2% of total electric load. This would offset all of the Company's
11 forecasted load growth and would obviate much of the capacity shortfall the Company
12 claims.

13 **Q: On what is this estimate based?**

14 A: A study prepared by Optimal Energy (including myself) and released in November of
15 2012 by Sierra Club looks at this question in detail.³ It surveyed potential studies
16 conducted in states similar to West Virginia and selected studies that 1) relied on similar
17 analytical methodologies; 2) contained the fewest limiting assumptions that would result
18 in an under-estimate of achievable potential; and, 3) had the most similar climatic,
19 geographic, and market conditions to West Virginia. The table below gives a summary of
20 the potential studies considered in the study.

³ "Save Money, Create Jobs: How Energy Efficiency Can Work for West Virginia," Prepared for the Sierra Club by Optimal Energy, Inc. 29 November 2012, attached hereto as Exhibit ER-JML-3.

Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
West Virginia PSC Case No. 12-1655-E-PC
June 18, 2013

| Energy Efficiency Potential Studies Review & Analysis | | | | | | | |
|---|------------|--------------|-------------------------|--|--|------------|------------|
| State | Study Year | Study Period | Analysis Period (Years) | Annual Achievable Cost Effective Potential | Total Annual Achievable Energy Savings by Sector | | |
| | | | | | Residential | Commercial | Industrial |
| Optimal Energy Estimate | | | N/A | 1.2% | 1.2% | 1.3% | 0.9% |
| Virginia | 2008 | 2008-2025 | 18 | 1.5% | 1.4% | 1.6% | 1.0% |
| Tennessee | 2011 | 2009-2030 | 21 | 0.9% | 0.9% | 1.1% | 0.9% |
| Kentucky | 2012 | 2010-2030 | 21 | 0.9% | 1.4% | 1.3% | 0.6% |
| North Carolina | 2006 | 2007-2017 | 11 | 1.3% | 1.5% | 1.1% | 1.1% |
| Maryland | 2008 | 2008-2025 | 18 | 1.6% | 1.7% | 1.9% | 0.0% |
| Arkansas | 2009 | 2008-2017 | 10 | 0.4% | 0.4% | 0.3% | 0.4% |

The study also reviewed the previously mentioned Summit Blue study prepared for APCo, presented below, which found an achievable energy efficiency potential of approximately 20% of total energy sales in the utility's territory over 20 years, or 1.0% per year.

| West Virginia - APCo Potential Study Results | | | | | | |
|--|------------|--------------|-------------------------|--|--|-------------------------|
| State | Study Year | Study Period | Analysis Period (Years) | Annual Achievable Cost Effective Potential | Total Annual Achievable Energy Savings by Sector | |
| | | | | | Residential | Commercial & Industrial |
| West Virginia - APCo | 2009 | 2009-2028 | 20 | 1.0% | 0.9% | 1.1% |

The Optimal "Save Money" report concluded that the studies from Virginia and Tennessee were best suited to provide a conservative estimate of the potential in West Virginia. The report analyzed the total potential estimates in the studies over the study periods to yield an annualized savings estimate for comparison across studies with different time horizons. The 1.2% annual savings number for West Virginia represents an average between the calculated annual percentage potential found for Tennessee and Virginia.

1 **Q: Do you believe this number is reliable enough to be used for power planning**
2 **purposes?**

3 A: I believe that 1.2% annual savings is an achievable level of efficiency given an
4 appropriate set of supporting policies and programs. If anything, it is likely to be a
5 conservative estimate of potential, for the following reasons:

- 6 • Most studies of energy efficiency potential do not fully look at the early retirement
7 retrofit market, in which old, inefficient equipment is retired before the end of its
8 useful life and replaced with new, more efficient equipment.
- 9 • As shown below, many other jurisdictions from across the country capture similar
10 levels of savings. Often, these jurisdictions have a long history of running efficiency
11 programs. Initial potential should be higher in West Virginia from lower net-to-gross
12 ratios, greater availability of “low-hanging fruit,” and a history of low retail prices.
- 13 • West Virginia has a very high percentage of manufactured housing and energy
14 intensive industries. Experience has shown that there is typically significant cost-
15 effective savings potential in both of these sectors.

16 Further, the 1.2% annual potential figure is consistent with the Summit Blue study.

17 **Q: Have utilities or other Program Administrators been able to actually achieve these**
18 **levels of savings?**

19 A: Yes, dozens of Program Administrators throughout the country have achieved such levels
20 of efficiency savings: at least twice or three times the levels assumed by the Company.

*Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
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- 1 The table below shows utilities in the U.S. with annual sales exceeding 1 million MWh
- 2 that acquired annual efficiency savings excess of 1.1% of sales.⁴

⁴ Data from EIA Form 861 for 2011.

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| Utility Name | Ownership | Efficiency as % of Sales |
|---|-----------------------|-------------------------------------|
| Cleveland Electric Illum Co | Investor Owned | 2.6% |
| Massachusetts Electric Co | Investor Owned | 1.7% |
| Southern California Edison Co | Investor Owned | 1.7% |
| United Illuminating Co | Investor Owned | 1.5% |
| PUD No 1 of Clark County - (WA) | Political Subdivision | 1.5% |
| Ohio Edison Co | Investor Owned | 1.5% |
| Los Angeles Department of Water & Power | Municipal | 1.5% |
| Puget Sound Energy Inc | Investor Owned | 1.5% |
| Western Massachusetts Elec Co | Investor Owned | 1.5% |
| Salt River Project | Political Subdivision | 1.5% |
| PPL Electric Utilities Corp | Investor Owned | 1.4% |
| Arizona Public Service Co | Investor Owned | 1.4% |
| Duquesne Light Co | Investor Owned | 1.4% |
| San Diego Gas & Electric Co | Investor Owned | 1.4% |
| Tucson Electric Power Co | Investor Owned | 1.4% |
| Rochester Public Utilities | Municipal | 1.3% |
| Connecticut Light & Power Co | Investor Owned | 1.3% |
| City of Tacoma - (WA) | Municipal | 1.3% |
| The Toledo Edison Co | Investor Owned | 1.3% |
| Duke Energy Indiana Inc | Investor Owned | 1.3% |
| The Narragansett Electric Co | Investor Owned | 1.3% |
| PUD No 2 of Grant County | Political Subdivision | 1.2% |
| Interstate Power and Light Co | Investor Owned | 1.2% |
| Northern States Power Co - Minnesota | Investor Owned | 1.2% |
| City of Pasadena - (CA) | Municipal | 1.2% |
| Idaho Power Co | Investor Owned | 1.2% |
| Snohomish County PUD No 1 | Political Subdivision | 1.2% |
| Pacific Gas & Electric Co | Investor Owned | 1.2% |
| Dayton Power & Light Co | Investor Owned | 1.2% |
| City of Seattle - (WA) | Municipal | 1.1% |
| Nevada Power Co | Investor Owned | 1.1% |
| City of Eugene - (OR) | Municipal | 1.1% |
| Tennessee Valley Authority | Federal | 1.1% |
| City of Burbank Water and Power | Municipal | 1.1% |
| City of Roseville - (CA) | Municipal | 1.1% |
| City of Glendale | Municipal | 1.1% |
| City of Fort Collins - (CO) | Municipal | 1.1% |
| Madison Gas & Electric Co | Investor Owned | 1.1% |

1

1 At the state level, the ACEEE 2012 State Efficiency Scorecard shows 12 states achieved
2 efficiency savings of between 0.5% and 1% of retail sales in 2010 (the most recent year
3 for which data are available),⁵ while an additional 9 states exceeded 1% savings per year.

4 Last, I note that public utility commissions, legislatures, and executive officers in
5 a wide range of jurisdictions have confirmed commitments to targets equal to or greater
6 than this 1.2% annual level, indicating a general consensus regarding the feasibility of
7 such targets. A summary prepared by ACEEE in September 2012 shows that 24 states
8 have enacted long-term (3+ years) binding energy savings targets.⁶ Furthermore, of 20
9 states with EERS policies in place for over 2 years, 13 were achieving at least 100% of
10 their goals and 3 were achieving over 90% of their goals.

11 **Q; How can Appalachian Power's current efficiency programs be quickly expanded to**
12 **begin capturing additional savings?**

13 A: There are several major markets that are not currently being addressed by APCo's
14 efficiency programs:

- 15 • Industrial efficiency: Appalachian Power has no efficiency programs directly
16 addressing industrial consumers. Comprehensive efficiency programs typically
17 achieve the largest and cheapest slice of energy savings from large industrial
18 consumers.
- 19 • Commercial & Industrial (C&I) custom program: While APCo offers mail-in rebates
20 to C&I customers for certain technologies, they offer no support to customers who

⁵ See ACEEE 2012 State Energy Efficiency Scorecard, <http://aceee.org/research-report/e12c>.

⁶ See ACEEE State Energy Efficiency Resource Standard Activity, <http://aceee.org/files/pdf/policy-brief/state-eers-summary-0912.pdf>.

1 may want to install an efficiency technology that is not on the fairly limited
2 prescriptive list, or who wants to take a comprehensive approach to efficiency. This
3 type of custom program provides a very significant portion of savings for a typical
4 efficiency portfolio.

- 5 • C&I direct install: it has been recognized that small C&I customers typically lack the
6 time and know-how to participate in standard C&I prescriptive and custom programs.
7 As a response, other jurisdictions have implemented direct install programs to better
8 address this market sector. Under a direct install program, a contractor visits a small
9 C&I customer, and directly installs lighting and other highly cost-effective measures
10 on the premise. Direct install programs have become integral to established efficiency
11 portfolios in helping small business owners achieve the cost benefits of increased
12 efficiency.

- 13 • Residential Appliance turn-in. This program focuses specifically on residential
14 customers, providing an incentive and free pick-up for old refrigerators and freezers
15 in a utilities' service area in order to take old, inefficient refrigerators and freezers off
16 of the market. The idea is that these refrigerators will either not be replaced (if it was
17 a lightly used secondary model), or get replaced with newer, much more efficient
18 models. This program is effective because there is a large secondary market for
19 refrigerators – the program ensures that old models will be recycled rather than
20 resold.

21 These are just some of the possible ways that APCo's portfolio could be expanded to
22 quickly achieve higher levels of savings than currently planned.

1 **Q: What about peak reduction? Are there examples of efficiency programs that have**
2 **yielded significant peak demand savings?**

3 A: Yes, programs in various regions and states have demonstrated that significant demand
4 savings are achievable from investment in energy efficiency. Perhaps most notable are
5 California's efforts to cut peak demand during the State's electricity crisis of 2000-2001.⁷
6 Efficiency and conservation-related programs reduced peak demand in California by an
7 estimated 3,668 MW in 2001. In addition, a 2007 study that reviewed 13 case studies of
8 efficiency programs that resulted in large peak demand reductions demonstrated that
9 efficiency programs in states like Texas, California, and Massachusetts had also achieved
10 substantial peak reductions, as shown in the table below.⁸ Furthermore, the Sixth
11 Northwest Conservation and Electric Power Plan, prepared by the Northwest Power and
12 Conservation Council, a group charged with developing and maintaining a regional
13 power plan for the Pacific Northwest, projected that the region could meet 85% of the
14 region's load growth over the next 20 years with energy efficiency.⁹ The peak demand
15 reduction potential calculated for the Company is thus readily achievable.

⁷ York, D., Kushler, M., and Witte, P. "Examining the Peak Demand Impacts of Energy Efficiency: A Review of Program Experience and Industry Practice." ACEEE Report Number U072. February 2007.
<http://www.aceee.org/research-report/u072>

⁸ *Ibid.*

⁹ Northwest Power and Conservation Council, "Sixth Northwest Conservation and Electric Power Plan," February 2010, <http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf>.

Table 2. Energy and Peak Demand Savings of Selected Programs

| State | Program Name | Annual Energy Savings (MWh) | Peak Demand Savings (MW) | MW/GWh [*] |
|-------|--|-----------------------------|--------------------------|---------------------|
| CA | San Francisco Peak Energy Program | 56,768 | 9.1 | 0.16 |
| CA | Northern California Power Agency SB5x Programs | 37,300 | 15.9 | 0.44 |
| CA | California Appliance Early Retirement and Recycling Program | — | — | — |
| TX | Air Conditioner Installer and Information Program | 20,421 | 15.7 | 0.77 |
| FL | High Efficiency Air Conditioner Replacement (residential load research project) | — | — | — |
| CA | Comprehensive Hard-to-Reach Mobile Home Energy Saving Local Program | 7,681 | 3.7 | 0.48 |
| MA | NSTAR Small Commercial/Industrial Retrofit Program | 27,134 | 6.0 | 0.22 |
| MA | 2003 Small Business Lighting Retrofit Programs | 35,775 | 9.7 | 0.27 |
| MA | National Grid 2003 Custom HVAC Installations | 980 | 0.17 | 0.17 |
| NY | New York Energy Smart SM Peak Load Reduction Program | — | 15.0 | — |
| MA | National Grid 2004 Compressed Air Prescriptive Rebate Program | 673 | 0.098 | 0.15 |
| MA | National Grid 2003 Energy Initiative Program—Lighting Fixture Impacts | 36,007 | 6.5 | 0.18 |
| MA | National Grid 2004 Energy Initiative and Design 2000plus: Custom Lighting Impact Study | 1,593 | 0.266 | 0.17 |

^{*} This column is derived values from reported peak demand savings and annual energy savings.

1

2 **Q: Have you made any specific year-by-year estimates of the potential additional**
3 **resources?**

4 **A: Yes, I have made estimates of the additional efficiency resource as shown in the table**
5 **below, which presents a high and a low estimate of available efficiency and demand**
6 **response resources for meeting the Company’s projected capacity requirements. These**
7 **demand side resources could represent between 43% and 67% of the Company’s forecast**
8 **capacity shortfall in 2022 and as much as three-quarters of the shortfall in 2026.**

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| | Cumulative EE Savings (GWh) | As a % of forecast load | Low Estimate | | High Estimate | | Cumulative new DR (MW) | As a % of forecast peak | Total DSM-low (MW) | Total DSM-high (MW) |
|------|-----------------------------|-------------------------|----------------------------|-------------------------|----------------------------|-------------------------|------------------------|-------------------------|--------------------|---------------------|
| | | | Cumulative EE Savings (MW) | As a % of forecast peak | Cumulative EE Savings (MW) | As a % of forecast peak | | | | |
| 2013 | 92 | 0.3% | 12 | 0.2% | 25 | 0.4% | - | 0.0% | 12 | 25 |
| 2014 | 261 | 0.8% | 35 | 0.5% | 70 | 1.0% | 117 | 1.7% | 151 | 187 |
| 2015 | 487 | 1.5% | 65 | 0.9% | 131 | 1.8% | 239 | 3.4% | 304 | 370 |
| 2016 | 808 | 2.4% | 114 | 1.6% | 217 | 3.1% | 358 | 5.0% | 472 | 575 |
| 2018 | 1,186 | 3.6% | 172 | 2.4% | 319 | 4.5% | 479 | 6.7% | 651 | 798 |
| 2017 | 1,555 | 4.7% | 227 | 3.2% | 418 | 5.8% | 482 | 6.7% | 710 | 901 |
| 2019 | 1,913 | 5.7% | 283 | 3.9% | 515 | 7.1% | 485 | 6.7% | 768 | 1,000 |
| 2020 | 2,256 | 6.7% | 336 | 4.6% | 607 | 8.3% | 488 | 6.7% | 823 | 1,095 |
| 2021 | 2,581 | 7.7% | 385 | 5.2% | 695 | 9.5% | 492 | 6.7% | 878 | 1,187 |
| 2022 | 2,880 | 8.5% | 431 | 5.8% | 775 | 10.5% | 496 | 6.7% | 927 | 1,271 |
| 2023 | 3,149 | 9.3% | 470 | 6.4% | 847 | 11.5% | 492 | 6.7% | 962 | 1,339 |
| 2024 | 3,385 | 9.9% | 505 | 6.8% | 911 | 12.2% | 501 | 6.7% | 1,006 | 1,412 |
| 2025 | 3,584 | 10.5% | 536 | 7.1% | 964 | 12.8% | 506 | 6.7% | 1,041 | 1,470 |
| 2026 | 3,753 | 10.9% | 562 | 7.4% | 1010 | 13.3% | 510 | 6.7% | 1,072 | 1,520 |

1

2 **Q: Please explain how you developed these data.**

3 A: As explained above, I began with an achievable energy efficiency savings potential of
4 1.2% per year on an energy basis. I then developed the projected savings based on several
5 factors, including the energy efficiency savings potential and the Company's forecast and
6 claimed energy and capacity needs.

7 **Q: Did you assume that the Company could begin acquiring 1.2% savings per year**
8 **immediately?**

9 A: No, I assume a ramp up period of four years from existing levels of efficiency, such that
10 the Company is not achieving the full 1.2% savings until 2017. This is a conservative
11 ramp up rate. In reality, new efficiency programs often experience a rush of program
12 activity in early years due to pent up demand, making it possible to achieve faster ramp
13 up rates.

14 **Q: How do those assumptions translate into the data in the table above?**

15 A: From these assumptions, I developed an estimate of effective cumulative efficiency
16 savings (as a percentage of load) in each year from 2013 through 2026, taking into

1 account both incremental savings each year and the decay in savings from measures
2 reaching the end of their useful life. The percent savings in each year were applied to the
3 load forecast in that year to determine each year's efficiency savings in MWh. These
4 energy reductions are then translated into peak capacity reductions. To do so, I reviewed
5 data presented by the Company in its filing and discovery responses. As with other
6 aspects of the analysis, I find different and inconsistent results with respect to the amount
7 of peak reduction that can be expected to result from a given amount of efficiency energy
8 savings, because of the different and inconsistent data in APCo's application. This ratio is
9 typically expressed as kWh/kW, with the kW normally taken to mean peak or coincident
10 kW. Depending on the different sets of source data from APCo, I calculated kWh/kW
11 ratios ranging from 3,716 to 7,656. The latter represents a portfolio of energy efficiency
12 with relatively poor on-peak coincidence, such as might occur with a large proportion of
13 savings from residential lighting. The former is more indicative of a broader portfolio that
14 includes efforts to address cooling loads in both residential and commercial sectors.¹⁰

15 As an aside, I note that if peak demand reduction is an important objective for an
16 efficiency portfolio, there are program designs that can be used to increase peak reduction
17 in proportion to energy reduction, such as emphasizing programs that reduce cooling
18 energy consumption and de-emphasizing residential lighting programs, which generate
19 relatively little peak savings. Furthermore, peak reduction can be achieved using demand
20 response programs specifically targeted at that result.

¹⁰ Although APCo is a winter-peaking utility, it's capacity requirements are driven by its participation in PJM, which is summer peaking.

1 **Q: Speaking of demand response, did you make any estimate of the potential for peak**
2 **reduction from demand response efforts, and if so, will you please explain?**

3 A: Yes. Similar to the estimate of expanded energy efficiency, I reviewed studies of
4 available demand response resource to develop an estimate of the resource that is
5 available to provide peak demand reduction in West Virginia. Using information
6 presented in a report by published by the Federal Energy Regulatory Commission
7 (FERC)¹¹, I estimated an additional 510 MW of capacity available from demand response
8 above and beyond current levels. This resource is not duplicative of currently realized
9 demand response resources in the Company's service territory, which are primarily
10 realized from large commercial and institutional customers and arranged by third-party
11 aggregators or through customer's direct participation in the PJM capacity markets.

12 **Q: Does your estimate represent an aggressive level of efficiency that may be difficult**
13 **or impossible to achieve?**

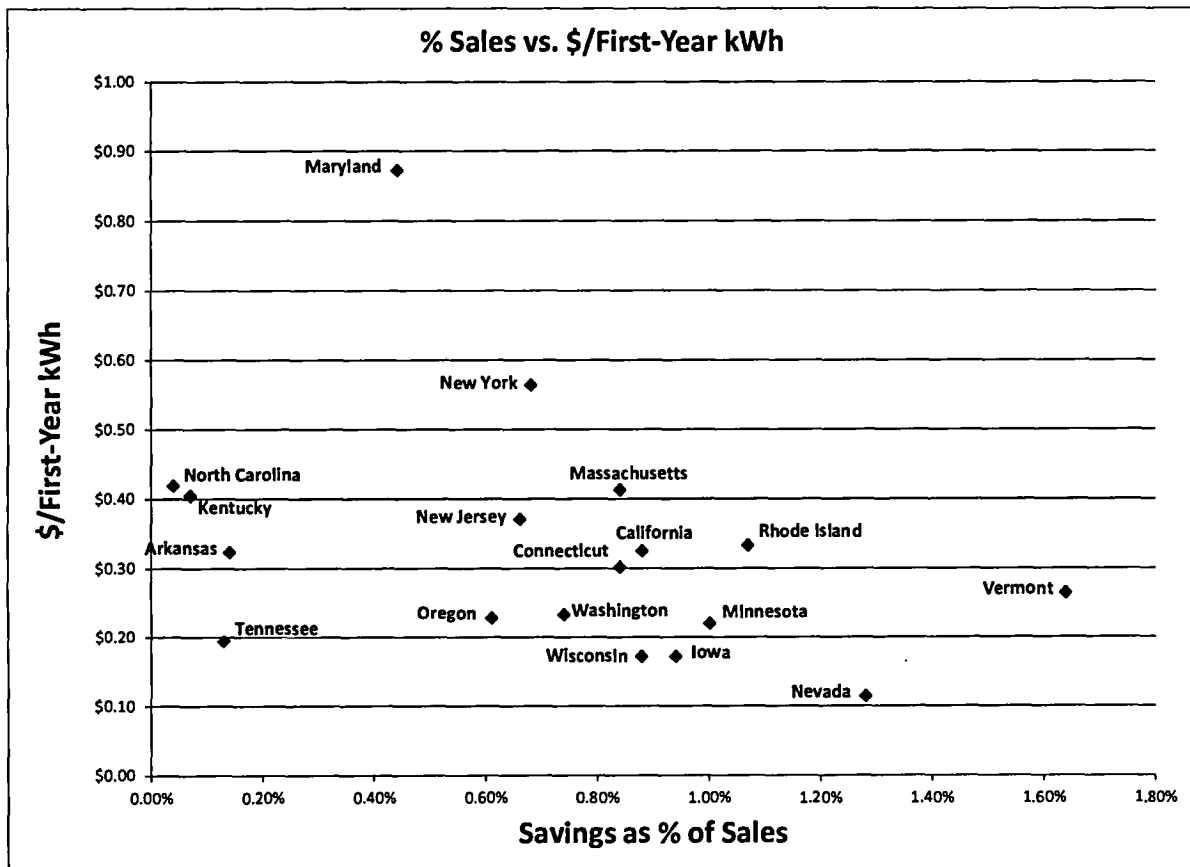
14 A: No, the strategies and policies that support this level of efficiency achievement are well-
15 studied and available for implementation in West Virginia.

16 **Q: What would be the cost of relying on efficiency and demand response for a greater**
17 **portion of the Company's load?**

18 A: The cost would be low and would deliver lower total customer bills, resulting in
19 significant consumer savings. The Optimal "Save Money" report referenced above also
20 estimates costs, based on actual program costs from other jurisdictions. For example,
21 2010 program data reported in the ACEEE 2012 Scorecard, an annual publication that

¹¹ See FERC, "A National Assessment of Demand Response Potential," <http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf>.

1 assesses empirical data of actual state energy efficiency program performance, shows that
2 many of the 13 top-performing states in energy efficiency (blue markers) are achieving
3 savings at costs between \$0.20 and \$0.40 per first-year kWh.¹²



4
5 In nearby jurisdictions, Maryland and Pennsylvania utilities spent on average \$0.23/first-
6 year kWh in 2010 and 2011. Data also indicate that efficiency savings are not getting

¹² ACEEE 2012 State Energy Efficiency Scorecard, <http://aceee.org/research-report/e12c>

1 more expensive over time. A report prepared in 2006 that looked at over a dozen states
2 and utilities found an average first-year cost of \$0.213/kWh.¹³

3 As a conservative estimate, for efficiency savings I adopt the cost used in the
4 “Save Money” report of \$0.30/kWh. This is based on the un-weighted average of all cost
5 estimates from the ACEEE scorecard of top-performing states. I also note that this is
6 higher than recent APCo experience as I noted earlier. My assumed cost is therefore
7 conservative.

8 This indicates an efficiency investment of approximately \$910 million for the
9 years 2013 through 2026 in present value terms using the Company’s discount rate. Note
10 that this investment will generate energy savings and peak reduction, and therefore
11 reduce customer energy bills, for many years beyond 2026 without any additional cost; as
12 discussed below, this savings would total in excess of \$1.2 billion.

13 For the cost of demand response programs, I estimate the cost of both new
14 demand response installations and the on-going payments to participants. These were
15 developed from the same source used to develop the estimate of demand response
16 capacity, plus additional reports published by the Natural Resources Defense Council¹⁴
17 and the Brattle Group.¹⁵ The additional cost of the demand response resource from 2013
18 through 2026 in present value terms using the Company’s discount rate is \$282 million.

¹³ Direct Testimony of Timothy Woolf before the Minnesota Office of Administrative Hearings, OAH No. 12-2500-17037-2, Exhibit JI-5-E.

¹⁴ See NRDC, “The Future of Demand Response: Connecting the Dots Between Smart Grid and Large Scale Wind Integration,” <http://www.maproyalty.com/downloads/the-future-of-demand-response.pdf>.

¹⁵ The Brattle Group. Direct Load Control of Residential Air Conditioners in Texas. October 25, 2012, http://www.brattle.com/_documents/UploadLibrary/Upload1093.pdf

1 **Q: What benefits accrue to the Company's ratepayers and customers as a result of this**
2 **spending?**

3 A: At the very least, customers who reduce their energy consumption as a result of
4 efficiency investments will see bill reductions on the order of \$1.2 billion over the 2013
5 to 2026 time frame, with further bill reductions continuing for several years after that as a
6 result of continued savings from efficiency measures installed through 2026 that continue
7 to generate savings over their entire useful lives. Furthermore, much of the spending on
8 DR goes directly to the program participants. Additional savings will accrue to both
9 participants and non-participants from Demand Reduction Induced Price Effects (DRIPE)
10 which I describe later in my testimony.

11 **Q: How does the cost of additional efficiency and demand response compare to the**
12 **costs for the proposed Mitchell and Amos Plants?**

13 A: Efficiency is clearly cheaper. The \$0.30/kWh cost for efficiency only represents the first
14 year savings from an efficiency measure. Since a typical efficiency measure life is
15 between 6 and 20 years, the cost for each kWh saved over the measure lifetime is only a
16 fraction of the first year cost. Depending on the measure, cost per lifetime kWh could
17 range from 5 to 1.5 cents, although measures with shorter lifetimes are also typically less
18 expensive, so the typical average cost per lifetime of efficiency is on the order of 3 cents.
19 The "Save Money" report presents levelized cost estimates for efficiency ranging from
20 1.7 to 4 cents per kWh. In contrast, the Company has suggested that the cost of energy
21 from the Amos and Mitchell plants is on the order of \$65/MWh, or 6.5 cents per kWh
22 (CAD Fifth Set Request A67 in Case 1101775-E-P).

1 **VI: Efficiency provides additional benefits to West Virginia consumers and citizens**

2 **Q: Apart from cost considerations, are there other benefits for West Virginia**
3 **consumers that result from increasing efficiency investments?**

4 **A: Yes, there are several additional benefits.**

- 5 • Reducing economic risks posed by regulatory risk, fuel price volatility, and
6 load forecast errors – Acquiring the Mitchell and Amos plants (or any similar
7 large, central generating stations) is an all-or-nothing proposition. Once the
8 plant is purchased, the Company’s ratepayers are committed to paying for its
9 entire cost and operation. This is true whether or not the load it purports to
10 serve materializes and regardless of the price of natural gas, coal or any
11 environmental control or compliance costs that may come into effect in the
12 future. With the exception of commodity prices for coal and gas, the Company
13 did not test the sensitivity of its analysis to these possible futures. Regardless,
14 these analyses are of limited diagnostic value, because none of them look at
15 expanded levels of efficiency and demand response. In contrast, energy
16 efficiency and demand response resources can be developed and deployed
17 incrementally to match actual conditions. This trades a large risk (i.e., a large
18 revenue requirement over a long period of time for a un-necessary or un-
19 economic capital investment) for a smaller one (i.e., the potential need to
20 acquire resources through market purchases or other shorter lead-time supply-
21 resources for a short period of time until additional resources can be
22 developed, whether through additional demand or supply side resources).

*Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
West Virginia PSC Case No. 12-1655-E-PC
June 18, 2013*

- 1 • Promoting local jobs and spending - Investments in energy efficiency create
2 jobs directly through the implementation of efficiency upgrades to buildings
3 and equipment and indirectly through subsequent spending of both job income
4 and bill savings from reduced energy consumption. In comparing efficiency
5 and renewable energy investments with the purchase of existing central station
6 generation like the Amos and Mitchell plant, it is important to note that none
7 of the large capital investment will create construction jobs in West Virginia:
8 these plants are already built. Furthermore, a large fraction of the costs of
9 operating the plants will be for coal. Even though the coal is mined in West
10 Virginia, the majority of the costs of coal are for the value of the commodity
11 itself, as opposed the labor needed to mine the coal and bring it to market.
12 More importantly, the Amos and Mitchell plant's continued operation in West
13 Virginia does not depend on whether or not the Company acquires the
14 proposed additional ownership stakes. No additional employment or spending
15 will be attributed to the acquisition. On the other hand, because the costs of
16 efficiency investments are limited largely to equipment and installation labor
17 and because all of these dollars represent new spending within the Company's
18 service territory, more of the dollars spent on efficiency will directly benefit
19 the West Virginia economy and its workers.
- 20 • Reducing the need for transmission and distribution upgrades - By slowing
21 load growth or even eliminating it in targeted areas, efficiency generates

1 additional benefits that may not be reflected in current avoided cost estimates
2 based on current energy market prices.

- 3 • Demand Reduction Induced Price Effects – The reduced energy demand due
4 to efficiency programs allows for the shedding of the most expensive
5 resources on the margin, thus lowering the overall cost of energy. This is
6 referred to as Demand Reduction Induced Price Effects (DRIPE). In New
7 England, where efficiency has made substantial reductions in load growth, this
8 effect has been estimated and is included in cost-effectiveness tests as an
9 additional benefit. A recently-released report from the Ohio Manufacturer’s
10 Association notes the importance of this effect in Ohio, where the price
11 mitigation resulting from full implementation of that state’s energy efficiency
12 resource standard through 2020 represent could total over \$2 billion, or a 60%
13 increase in benefits above the already cost-effective wholesale energy savings
14 resulting from that policy.¹⁶ Even if the effect is smaller and goes un-assessed
15 in West Virginia, it represents another benefit of efficiency over traditional
16 supply-side options.

- 17 • Increasing efficiency program participation means fewer non-participants and
18 greater equity – As I discuss later, distributional equity can potentially be a
19 concern with efficiency programs, depending on program design. Ideally,
20 programs implemented by APCo would ensure that all Appalachian Power

¹⁶ Neubauer, M, et al. *Ohio’s Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State*. ACEEE Report Number E138, April 2013.
http://www.ohiomfg.com/communities/energy/OMA-ACEEE_Study_Ohio_Energy_Efficiency_Standard.pdf

1 customers are given the opportunity to lower their bills through participation
2 in efficiency programs. Greater levels of investment in efficiency programs
3 make it more feasible for all customers to participate at some level and
4 minimizes the number of non-participants who may see bill increases as a
5 result.

6 **Q: With respect to your mention of the job impacts from spending on efficiency and**
7 **demand response, can you provide any estimate of the potential job impacts?**

8 A: Yes. As detailed in the “Save Money” report I referenced earlier, estimates of job
9 creation from spending on efficiency investments ranges from 43 to 250 jobs per million
10 dollars invested in efficiency. This figure represents net jobs – it accounts for the
11 opportunity costs in the energy and utility field that may see lower spending or see their
12 growth curves bent downward as a result of efficiency. Again adopting the value used in
13 that analysis (54.7 jobs per million dollars), the job impacts from the efficiency
14 investments I described earlier reach nearly 4,000 jobs in 2016 and over 6,000 jobs from
15 2017 onwards. Importantly, most of this job creation would be located in West Virginia,
16 as efficiency spending is composed largely of local labor (contractors, engineers,
17 program staff, etc) and products typically purchased from local retailers and distributors.
18 Furthermore, these estimates do not include any assessment of the job creation resulting
19 from the demand response spending included in my analysis, which would also require
20 local labor for equipment installation.

21 **Q: Do you share the concerns that are sometime expressed with respect to**
22 **distributional effects on ratepayer that can result from efficiency programs?**

*Direct Testimony of Jeffrey Loiter
on behalf of the Sierra Club
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June 18, 2013*

1 A: Only to a limited extent. While it is true that energy efficiency programs will slightly
2 raise both rates and bills for some customers who choose not to participate in the
3 programs, approving the Amos and Mitchell acquisitions will result in rate increases for
4 ALL of Appalachian Power's customers, none of whom will have a choice as to their
5 participation in this investment. Witness Ferguson notes "the transfer of the Generating
6 Assets will require an approximate \$130 million increase in base rates" (p.11) and the
7 Company's response to WVCAG in case 11-1755, Request 2-2 puts the total net rate base
8 of the proposed assets at \$1.2 billion. I understand that taking an action that raises
9 customers' energy bills should not be undertaken lightly and requires careful
10 consideration of distributional effects. Nevertheless, it is important to point out that it is
11 misleading to only consider these effects as they might result from efficiency. The choice
12 is not between doing efficiency and doing nothing. As clearly indicated by this case, the
13 choice presented is between committing well a large sum of ratepayer funds to acquire
14 Mitchell and Amos (and substantial additional funds to pay for the energy generated over
15 its life) and investing in resources with lower total costs for West Virginia's ratepayers.
16 The latter course better protects the public.

17 **Q: Does this conclude your testimony?**

18 A: Yes, it does.

**BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|--|---|-------------------------|
| In the Matter of the Application of Ohio |) | |
| Edison Company, The Cleveland Electric |) | |
| Illuminating Company, and The Toledo |) | Case Nos.12-2190-EL-POR |
| Edison Company For Approval of Their |) | 12-2191-EL-POR |
| Energy Efficiency and Peak Demand |) | 12-2192-EL-POR |
| Reduction Program Portfolio Plans for 2013 |) | |
| through 2015 |) | |

**DIRECT TESTIMONY
OF
JEFFREY LOITER
ON BEHALF OF THE
OHIO SIERRA CLUB**

October 5, 2012

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1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Jeffrey Loiter and my business address is Optimal Energy, Incorporated, 14
4 School Street, Bristol, VT 05443

5 **Q. On whose behalf are you testifying?**

6 A. I am testifying on behalf of Sierra Club.

7 **Q. Mr. Loiter, by whom are you employed and in what capacity?**

8 A. I am employed as a Managing Consultant by Optimal Energy, Inc, a consultancy
9 specializing in energy efficiency and utility planning. In this capacity, I direct and
10 perform analyses, author reports and presentations, manage staff, and interact with clients
11 to serve their consulting needs. My clients include utilities, NGOs, state energy offices
12 and efficiency councils, and third-party program administrators. For example, I provide
13 Orange & Rockland Utilities with consulting services on program design and
14 implementation and participate on the consultant team supporting the work of the
15 Massachusetts Energy Efficiency Advisory Council.

16 **Q. Please summarize your work experience and educational background.**

17 A. I have 15 years of experience in environmental and economic consulting. For the past 6
18 years, I have been engaged in a variety of work at Optimal Energy related to energy
19 efficiency program design and analysis. For example, I prepared two documents for
20 inclusion with EPA's *National Action Plan for Energy Efficiency (NAPEE)*: a guidebook

1 on conducting efficiency potential studies, and a handbook describing the funding and
2 administration of clean energy funds.¹

3 In my capacity as a Managing Consultant at Optimal, I also advise clients on
4 efficiency program design and implementation. For example, I recently contributed to a
5 5-year Energy Efficiency and Demand Response Plan for the Tennessee Valley
6 Authority. I have also participated in several studies of efficiency potential and
7 economics, including ones in New York, Vermont, Texas, Massachusetts, and Prince
8 Edward Island. These studies have ranged from macro-level assessments to extremely
9 detailed, bottom-up assessments evaluating thousands of energy efficiency measures
10 among numerous market segments. In addition, I support a utility client that participates
11 in the ISO New England Forward Capacity Market with their efficiency resource.

12 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
13 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
14 Environmental Engineering from Cornell University and an *M.S.* in Technology and
15 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
16 1.

17 **Q. Have you previously testified before the Public Utilities Commission of Ohio (“the**
18 **Commission” or “PUCO”)?**

19 **A. No.**

20 **Q: What is the purpose of your testimony?**

21 **A: The purpose of my testimony is to provide comments on the 2013-2015 Energy**
22 **Efficiency and Peak Demand Reduction Program Portfolio Plans (“Plan”) of Ohio Edison**

¹ These documents can be found at http://www.epa.gov/cleanenergy/documents/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

1 Company, The Cleveland Electric Illuminating Company, and The Toledo Edison
2 Company (“FirstEnergy” or “Companies”) and to recommend changes that would, in my
3 opinion, benefit the Companies’ customers and Ohio citizens. My testimony focuses on
4 the programs for non-residential customers and on the issue of bidding DSM resources
5 into the PJM forward capacity market.

6 **Q: Please summarize your conclusions.**

7 A. My review and assessment of the Companies’ DSM Plan (“Plan”) and related materials
8 leads me to conclude that 1) the Companies are inappropriately withholding planned
9 efficiency savings from the PJM forward capacity market and 2) the Plan is flawed and
10 will lead to weak or uncertain achievement of the required benchmarks.

11 **Q: What actions do you recommend the PUCO take in this proceeding?**

12 A. I recommend that the PUCO take the following actions:

- 13 1. Require Companies to bid planned efficiency and demand response savings into the
14 next PJM Base Residual Auction
- 15 2. Deny the Companies’ request to retain the option to petition for reconsideration of the
16 order related to savings ownership
- 17 3. Direct the Companies to reduce spending on efficiency kits for small enterprise
18 customers in favor of alternative strategies better suited to this customer class, such as
19 a “direct install” program
- 20 4. Direct the Companies to eliminate incentives for baseline lighting technologies,
21 regardless of the efficiency of existing fixtures
- 22 5. Direct the Companies to enhance the role of account executives with respect to
23 efficiency programs from “advisory” to an integral part of the sales strategy.

1 6. Direct the Companies to acquire more savings from large customers participation in
2 FirstEnergy programs, rather than from actions these customers would take regardless
3 of the Companies involvement or financial contribution.

4 **II COMPANIES' PARTICIPATION IN PJM BASE RESIDUAL AUCTIONS**

5 **Q: Why do you recommend that the Companies be required to bid planned efficiency
6 and demand response savings into the PJM Base Residual Auction?**

7 **A: First and foremost, the failure to bid the savings from planned efficiency program savings
8 results in substantially higher costs for FirstEnergy's customers. This comes in the form
9 of both lost revenue from the proceeds of the auction and from the likelihood that
10 FirstEnergy's efficiency and demand response resources would likely have reduced the
11 clearing price of the auction, thus saving FirstEnergy's customers money on *every* MW
12 needed to fulfill their load obligation.**

13 **Q: Does FirstEnergy give any reasons why they choose not to bid planned savings into
14 the auctions?**

15 **A: Yes, the Companies' objections to bidding the savings center on uncertainty regarding
16 both the achievement and ownership of future savings.**

17 **Q: Are these concerns warranted?**

18 **A: No. First, the PJM BRA framework includes not only the initial auction three years in
19 advance of the delivery date for capacity, but additional incremental auctions in which
20 market participants can continue to buy and sell the obligation to provide capacity.
21 Should the Companies find that, say, two years after the initial auction, they believe they
22 will not achieve their forecast savings, they can shed part of their obligation in the later
23 incremental auctions, thus mitigating this risk.**

1 Second, to the extent that the Companies are unwilling to stand behind their
2 projections for program results, the Commission should adopt the recommendations
3 made in my testimony and in the testimony of Environmental Intervenor's other witness
4 to add assurance that they will in fact achieve savings in excess of the required minimum
5 benchmarks.

6 **Q: Is there precedence for this type of bidding approach?**

7 A: Absolutely. Other utilities in both ISO-NE and PJM successfully bid future, planned
8 efficiency resources into the market, particularly when based on legislatively-mandated
9 spending and savings targets. For example, I advise a client that participates in the ISO
10 New England Forward Capacity Market (FCM) that has bid most of their planned
11 efficiency savings into several auctions. I am also aware the Efficiency Vermont
12 participates in the ISO-NE FCM with most of their planned efficiency resource.

13 **Q: The Companies have raised concern that the Commission decision in the ESP case
14 regarding ownership of savings that result from participation in the Companies'
15 programs will cause a "chilling effect" on program participation. Do you share this
16 concern, and if not, why not?**

17 A: No, I do not. I disagree with the Companies' interpretation of information they provided
18 regarding this issue. These data purport to show that 45 percent of commercial and
19 industrial customers who participated in un-named programs in Pennsylvania opted to
20 retain ownership of the energy efficiency resource attributes, representing approximately
21 half of the associated projects in energy savings (SC Set 3-INT-81, Attachment 1). This
22 datapoint has no bearing on the Companies' likely program achievement.

23 **Q: Why not?**

1 A: The fact that some customers choose to take advantage of a potentially better deal (in the
2 form of retained ownership rights to savings) when it is offered does not prove that these
3 same customers would NOT take an offer that did not include these rights. It is unlikely
4 that customers will forego hundreds or thousands of dollars in rebates or incentive
5 payments for the much smaller monetary benefits received from direct participation in the
6 auction, particularly given the resources and expertise needed to support that
7 participation. Another way to look at this result is that despite the perceived value of
8 these rights, less than half the customers chose to retain them. This could imply a much
9 lower hurdle for the Companies to retain rights to all or nearly all of the savings from
10 program participants, since half may already be ready to give them up. The Companies
11 have not provided sufficient evidence for the Commission to determine that they will be
12 unable to achieve their planned savings when they retain ownership of the credits as
13 directed to by the Commission.

14 **Q: But what if FirstEnergy is right and participation does suffer? Won't they then fall**
15 **short of their PJM obligation?**

16 A: No, because the structure of the market allows for adjustments to obligations at a later
17 date, as described above. In fact, to the extent that the incremental auctions clear at a
18 price lower than the original base residual auction, the Companies can actually make
19 money on this difference. For example, the second and third incremental auctions for the
20 2012/2013 delivery period in the zone in which the Companies' operate (RTO) closed
21 lower than the original Base Residual Auction. This was also true for the first and second
22 incremental auctions for the 2013/2014 delivery period.² As a result, the Companies

² *Second Performance Assessment of PJM's Reliability Pricing Model*, Published by The Brattle Group, 26 August 2011; PJM RPM Incremental Auction Results, <http://pjm.com/markets-and-operations/rpm/~media/markets->

1 could have shed part of their obligation and earned the difference of the clearing prices
2 for that quantity.

3 **Q: What then is your recommendation to the Commission on this topic?**

4 **A:** I recommend that the commission deny the Companies' request to retain the option to
5 petition for reconsideration of the order related to savings ownership.

6 **III FLAWS IN THE COMPANIES' PLANS**

7 **Q: You stated that you conclude the Plan is flawed and will lead to weak or uncertain**
8 **achievement of the benchmarks. What is the basis for this conclusion?**

9 **A:** There are several contributing factors.

- 10 • The Companies' programs are under-funded, leading to high free-ridership and risk of
11 under-performance.
- 12 • The Companies' deployment of "kits" (high free-rider) instead of a direct install
13 program.
- 14 • The Companies are providing incentives for baseline lighting technology.
- 15 • The Companies are not fully utilizing or encouraging account representatives to
16 promote new efficiency projects at large customer facilities.
- 17 • The Companies are counting substantial savings from demand response actions that
18 are unrelated to program efforts and that would take place regardless of Companies
19 actions.

20 Taken together, these concerns create uncertainty that FirstEnergy will meet its benchmarks.

21 **Q: Please explain how the programs may be under-funded.**

[ops/rpm/rpm-auction-info/2012-2013-third-incremental-auction-report.ashx](http://rpm/rpm-auction-info/2012-2013-third-incremental-auction-report.ashx), <http://pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/2013-2014-first-incremental-auction-report.ashx>,
<http://pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/2013-2014-second-incremental-auction-report.ashx>

1 A: The programs as filed take shortcuts towards meeting the benchmarks, including as over-
2 reliance on inexpensive efficiency kits and no-cost savings claimed from customers'
3 demand response efforts outside of program efforts. While cost-efficiency is an important
4 consideration in program design, I believe that it is possible for programs to be too
5 inexpensive and therefore risk being penny-wise and pound-foolish.

6 **Q: How can the programs be too inexpensive?**

7 A: Low incentives may not be sufficient to induce program participation by customers,
8 particularly if not supported by a robust support effort that includes marketing, trade ally
9 development, and efficient customer engagement systems. A recent program evaluation
10 found trade allies indicating that incentives may in fact be too low (ADM Associates,
11 Appendix G, 2011 Evaluation of EnergySaveOhio Commercial and Industrial Energy
12 Efficiency Incentive Programs, Case No. 12-1533-EL-EEC, et al. at 20, Table 5-19). If
13 incentives are too low, they play a limited role in customer decision-making. As a result,
14 few customers are prompted to switch from standard efficiency to high efficiency
15 options, and those that do take advantage of the incentive are more likely to have made
16 that choice even in the absence of the incentive. The latter group are known as "free-
17 riders." They represent wasted program spending, because the amount of efficiency
18 investment has not increased and energy consumption has not been reduced below what it
19 would have been in the absence of the program spending. That fact that the Companies'
20 benchmarks are in terms of gross rather than net savings does not mean that they should
21 PLAN for high free-ridership, at the expense of ratepayers.

22 **Q: What should the Companies do to remedy this situation?**

1 A: First, the Companies should benchmark their incentives with neighboring utilities,
2 particularly those within Ohio. Higher incentives will induce greater participation and
3 lower free-ridership, potentially lowering the real cost of efficiency savings. It will have
4 the added benefit of minimizing trade ally and customer confusion regarding incentive
5 levels in areas near the borders between two different utilities. Second, they should
6 continue to closely monitor free-ridership, particularly for basic efficient lighting
7 products that are already becoming widespread.

8 Q: What other concerns do you have about the Plan?

9 A: The proposed programs for non-residential customers (both small enterprise and
10 mercantile customers) rely on problematic measures or program approaches for large
11 portions of their savings (both energy and demand).

12 Q: Can you provide an example of this?

13 A: Yes. One of the most problematic aspects of the proposed small enterprise program is the
14 over-reliance on efficiency kits. Similar to the kits that will be provided to residential
15 customers, these represent nearly 40 percent of the cumulative three-year savings for the
16 small commercial sector for Ohio Edison and nearly 30 percent of the cumulative three-
17 year savings for this sub-sector for the other two operating companies. Furthermore, these
18 kits have a measure life of just three years. That is, while they will contribute to the 2013-
19 2015 benchmarks, they provide little in the way of lasting savings for 2016 and beyond.
20 After 2016, the remaining savings from the Small Enterprise segment of the Companies'
21 programs will be dramatically diminished. Last, I reference concerns regarding the
22 Companies' assumed in-service rate and savings estimates for the kits made by Glenn

1 Reed in his testimony. I share those concerns with respect to the kits in the small
2 enterprise program.

3 **Q: Why aren't the kits a good strategy for addressing small enterprise customers?**

4 **A:** An efficiency program must address the customer's barriers to choosing efficient
5 equipment, regardless of the market or customer type being targeted. Smaller business
6 customers face several barriers in the efficiency marketplace. First, these firms rarely
7 have personnel who can focus their attention on issues of facility management and energy
8 use, even if they had the knowledge and skill to do so. Second, smaller firms have more
9 limited access to capital. Because higher efficiency equipment typically requires a larger
10 up-front investment which is then recovered through lower operating costs, these firms
11 may not be able to make economically beneficial investments at all. Third, the
12 management staff of smaller firms are typically wearing multiple hats and have limited
13 time to devote to reviewing offers, negotiating with vendors, and completing paperwork.
14 The efficiency kits address, at best, only the issue of limited capital, because the
15 equipment is provided for free. The program does not help the customer understand the
16 benefits of investing in higher efficiency equipment and falls far short of addressing
17 enough of the customer's energy use to make a meaningful impact on their overall energy
18 bill.

19 **Q: Can you recommend an alternative program strategy?**

20 **A:** Yes. A common strategy used by efficiency programs to addresses these barriers is the
21 direct install model. This approach combines high incentives with simple program
22 requirements and prescriptive measures to easily address many of the most common
23 efficiency opportunities in small businesses. Other utilities have found that this approach

1 results in very high rates of participation in the targeted customer base. The direct-install,
2 turn-key model was first offered by National Grid in 1990 in Massachusetts, and has
3 continued to be a part of Massachusetts' electric utility program. AEP-Ohio currently
4 runs a successful Express program (recently approved by the Commission) that provides
5 participating small businesses with a range of services to overcome these barriers.

6 **Q: Do you have concerns with any other areas of the programs?**

7 A: Yes, another example is related to the type of technology for which the Companies will
8 provide an incentive. The Companies' interrogatory response to SC Set 1-INT-48
9 (Attachment 2) states that standard 32W T8s are considered baseline technology. That is,
10 they represent the lowest efficiency equipment that can be installed and serve as the basis
11 of comparison for more efficiency technologies. On the other hand, the Companies'
12 interrogatory response to NRDC Set 3-INT- 31 (Attachment 3) indicates that the program
13 will provide customers with rebates for these standard T8s in situations where the
14 customer is upgraded from older T12 lighting. The Energy Independence and Security
15 Act of 2007 (EISA) eliminated manufacturing of T12s and low-efficiency T8s, so they
16 will soon be disappearing from business installations without any influence on the part of
17 the Companies. While it is appropriate to count the additional savings from a customer's
18 existing T12 baseline for a short period of time (as is the case in, for example,
19 Massachusetts), the Companies should not settle for bringing these customers up to
20 standard T8s. Doing so fails to help transform the market towards the higher-efficiency
21 choice and can create confusion among customers and implementers regarding what
22 qualifies as an efficient lighting choice.

23 **Q: What do you recommend be done instead?**

1 A: It takes resources (both time and money) to reach customers and convert them to program
 2 participants. Rather than stop at the baseline technology they will soon reach as a result
 3 of federal standards, the program should bring all customers with whom they engage to
 4 the high performance lighting fixtures that are the focus of the rest of the lighting
 5 program. The greater savings from the higher efficiency technology come at very little
 6 additional cost, particularly when you consider the additional administrative cost of
 7 trying to reach this same customer again at a later date to bring them to the higher
 8 efficiency level. For example, the incremental cost of a high performance 2-lamp T8
 9 fixture over a standard T8 fixture is just \$18, compared with a cost of \$100 for the fixture
 10 retrofit in the first place, yet this increases savings by almost 50 percent.

| <u>2-lamp, 4-foot fixtures</u> | <u>Wattage</u> | <u>Savings (Watts)</u> |
|--------------------------------|----------------|------------------------|
| T12 existing | 94 | N/A |
| T8 baseline | 59 | 35 |
| HPT8 efficient | 43 | 16 |

| | <u>Cost</u> | <u>Savings (Watts)</u> |
|---|-------------|------------------------|
| T12 to HPT8 retrofit | \$100 | |
| HPT8 vs. T8 incremental | \$18 | 16 |
| Assumed cost of T12 to standard T8 retrofit | \$82 | 35 |

| | | |
|---|------------|------------|
| <u>increase from T8 to HPT8 as target equipment</u> | <u>22%</u> | <u>46%</u> |
|---|------------|------------|

11 Source: State of Illinois Energy Efficiency Technical Reference Manual

12 Furthermore, setting a uniform minimum eligibility (rather than one based on the
 13 customer's existing equipment) avoids contractor and customer confusion regarding
 14 eligible products.

15 **Q: Is this a new approach?**

16 A: No, other utilities in Ohio have already removed incentives for T12 to standard T8
 17 fixtures from their programs. Duke Energy Ohio announced in February that they would

1 eliminate these incentives in late 2012, requiring now-baseline equipment to be
2 purchased by July 15, 2012 and installed no later than October 15, 2012.³

3 **Q: Are your recommendations limited to the programs for smaller customers?**

4 **A:** Not at all. I have recommendations regarding programs for larger “mercantile” customers
5 as well. To begin with, I note that these customers represent a large portion of the
6 Companies’ electric load (38 percent across all three EDUs, according to data presented
7 in Appendix C-3, PUCO 5A) and a proportionate portion of the available savings (27
8 percent across all EDUs, same source). Furthermore, the cost of savings from large
9 customers tends to be lower than for smaller commercial and residential customers.
10 FirstEnergy’s own projections for the three EDUs have the small enterprise programs
11 costing twice the amount of the large enterprise programs on a dollar-per-lifetime-MWh
12 basis, despite the prevalence of the very inexpensive efficiency kit savings in the former.
13 Best practice programs therefore place substantial effort and resources into working with
14 these customers to generate program savings. The Companies fail to propose programs
15 that will leverage these customers’ potential to the fullest.

16 **Q: What do you recommend be done differently?**

17 **A:** To begin with, the Companies need to realize that reaching large commercial and
18 industrial accounts is best accomplished through dedicated account executives.
19 Unfortunately, the Companies state that their existing large customer account executives
20 will serve only an “advisory role” for the programs. This fails to leverage these important
21 relationships for efficiency. Account executives should be *selling* efficiency to their
22 accounts as an integral part of that relationship. Furthermore, the account executives

³ See <http://www.duke-energy.com/ohio-business/smart-saver/smart-saver-incentive-updates.asp>, “Incentives for T12 to standard T8 and T5 retrofits to end.” Dated 13 February 2012, accessed 2 October 2012.

1 should be utilized as a key source of information on the efficiency needs of this customer
2 segment. Program updates should be based on discussion with and feedback from these
3 customers, not just a bundle of information that account executives pass along.

4 **Q: Do you have any other concerns about the large customer programs?**

5 **A:** Yes. Similar to my concerns with the use of the efficiency kits in the small enterprise
6 sector, it seems that a substantial portion of the savings in the large customer segment,
7 are coming from measures with very high levels of potential free-ridership. This is true
8 for both energy and demand savings, and even more so than in the small enterprise
9 segment. In fact, while the Companies claim these savings are reasonable and within the
10 bounds of Ohio law and practice, they would likely not be acceptable in other
11 jurisdictions.

12 **Q: What savings are you specifically concerned with?**

13 **A:** I am most concerned with the demand savings from customers' existing participation in
14 demand response markets and from mercantile customers self-direct projects. The
15 Companies are proposing to claim savings from demand response actions by market
16 participants that are occurring or will occur without any intervention from the Companies
17 or their programs. In effect, these savings are the result of the market baseline demand
18 response activity. These are, without debate, "free-rider" savings and are therefore not
19 attributable to the Companies. The Companies claim that this should not be relevant to
20 the discussion, stating that they "are not aware of a specified requirement that a utility
21 needs to offer an incremental program incentive to the resources participating in such a
22 program" (SC Set 2-INT-70, included as Attachment 4). While it is true that incentives
23 are not the only way to influence customer behavior towards efficiency investments or

1 demand response program participation, the Companies have not provided any indication
2 that they took any action, financial or otherwise, to cause the subject demand response
3 savings to exist. If no action is taken by the Companies, there is no program. I am not an
4 attorney, but I interpret the legislation to require the utility to offer programs in order to
5 demonstrate compliance with the benchmarks, or make use of mercantile customer
6 capabilities, “existing or new.” In my opinion, the law does not allow the Companies to
7 “take” another’s efficiency or demand response to demonstrate compliance. If that were
8 the case, then the Companies could also take credit for savings resulting from, say, a local
9 climate action group passing out CFLs on Election Day. The point of the energy
10 efficiency and demand reduction benchmarks is to create activity beyond what would
11 have happened anyway. Otherwise, there would be no reason to have benchmarks. These
12 same objections hold true for the savings from self-direct projects at large mercantile
13 customers.

14 **Q: What is the effect of these savings on the overall portfolio?**

15 **A:** The peak demand savings from customer demand response efforts represent one-half to
16 two-thirds of the total demand reduction from the entire proposed portfolio. The
17 mercantile self-direct customer savings represent approximately one-fifth of the proposed
18 energy savings. Absent these savings, which I recommend be denied by the Commission,
19 the Companies have not presented a plan that will achieve the peak demand reduction
20 benchmarks over the next three years.

21 **Q: What remedy do you recommend to address this concern?**

22 **A:** There are many program options available to address the large customer class that
23 provide a much stronger connection between program spending and program savings. I

1 recommend that the companies re-allocate their spending to achieve a much higher
2 proportion of their savings from focused efforts with these customers, through programs
3 that identify cost-effective equipment upgrades and planned process improvements.

4 **IV. CONCLUSION**

5 **Q: Does this conclude your testimony?**

6 **A.** Yes, but I reserve the right to add or modify my testimony based on new or additional
7 information received or discovered.

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing *Direct Testimony of Jeff*

Loiter has been served upon the following parties via electronic mail on October 5, 2012.

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Christopher J. Allwein

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**JEFFREY M. LOITER
MANAGING CONSULTANT**

Mr. Loiter has over 14 years of consulting experience in energy and natural resource issues. His energy experience includes policy, planning and program design, research on renewable and efficiency technologies, electricity transmission systems, integrated resource planning and savings verification. As a Managing Consultant, Mr. Loiter manages projects, oversees staff development, and contributes to firm management in the areas of hiring and business development.

PROFESSIONAL EXPERIENCE

Optimal Energy, Inc.

Bristol, VT

Managing Consultant, 2006-present

- Managing Optimal's participation in a team developing a Five-Year Energy Efficiency and Demand Response Plan for the Tennessee Valley Authority. Optimal's role focused on programs for the commercial sector in TVA's service territory, encompassing efforts to reach a variety of markets and end-uses, including specific offerings for both very large and small commercial entities.
- Supporting Efficiency Vermont Business Energy Services group with technical analysis, market research, and program design consultation. Recent projects include market characterization studies of refrigeration, lodging establishments, and food service entities; and developing several Technical Resource Manual entries.
- Supporting Massachusetts Energy Efficiency Advisory Council on program planning and implementation and technical analysis. Currently participating in the CHP Working Group, guiding program implementation strategies and analytical approaches.
- Supporting program implementation and on-going program design and development for Orange and Rockland Utilities. Previously managed the preparation of a DSM plan and Commission filings for this client. The project included on-site customer audits and residential surveys, efficiency program designs, and an efficiency potential study.
- Prepared comments and related materials on utility IRP filings in support of the Missouri Department of Natural Resources. Review focused on compliance with IRP regulations and critique of filed DSM plans as compared to best-practice.
- Led Optimal's participation in preparing a Technical Resource Manual for the Mid-Atlantic States (Maryland, Delaware, District of

Columbia), for the Northeast Energy Efficiency Partnerships' Regional EM&V Forum.

- Supported the Maryland Energy Administration in their review of utility energy efficiency plans and the design and implementation of state-delivered efficiency programs.
- Provided recommendations to improve a targeted DSM program being delivered under contract to a major northeast electric utility. Interviewed program staff and provided recommendations based on best practice approaches for similar target markets.
- Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.
- Conducted potential analysis for a Canadian Atlantic province, including commercial and institutional sector program design and overall analytical oversight.
- Developed residential potential analysis for the non-transmission alternative to a proposed transmission line upgrade in Vermont.
- Prepared report on efficiency potential in Texas in support of discussions related to proposed expansion of coal-fired generating capacity, for two major NGOs.

Independent Consultant

Cambridge, MA

2005-2006

- For the Massachusetts Renewable Energy Trust SEED Initiative, evaluated renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards recommended for approval totaled \$1.4 million.
- Led an effort to draft a whitepaper on policies to encourage investment in electricity transmission facilities.
- Prepared two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in *Petroleum Technology Quarterly* (1Q 2006) and *BCC Research/Energy Magazine* (2006).

Industrial Economics, Incorporated

Cambridge, MA

Associate, 1997-2000; Senior Associate, 2001-2004

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Incorporated

New Orleans & Boston

1991-1995

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

EDUCATION

M.S., Technology & Policy, Massachusetts Institute of Technology, Cambridge, MA, 1997

B.S. with distinction, Civil and Environmental Engineering, Cornell University, Ithaca, NY, 1991

PUBLICATIONS

"From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers," (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings*, Pacific Grove, CA, August 2008.

National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies*. Prepared by Philip Mosenthal and Jeff Loiter, Optimal Energy, Inc. December.

Loiter J.M and V. Norberg-Bohm (1999), "Technology policy and renewable energy: public roles in the development of new technologies," *Energy Policy* Vol.27 no.85-97

Case No. 12-2190-EL-POR, Case No. 12-2191-EL-POR, Case No. 2192-EL-POR

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company For Approval of Their Energy Efficiency and Peak Demand Reduction Program Portfolio Plans for 2013 through 2015

RESPONSES TO REQUEST

SC Set 3–
INT-81

Please identify all documentation detailing all actual results from other jurisdictions, as referenced by Witness Dargie, that support the conclusion that a Commission directive requiring ownership of savings will have a chilling effect on program participation.

Please provide program names, descriptions – including rebate structure and levels-, and the terminology used to express ownership of the savings in these programs from other jurisdictions.

For which of the Companies' Ohio programs is this chilling effect expected to take place?

Response:

Objection. This request seeks the confidential information of third parties who are not parties to this proceeding. This request also mischaracterizes Witness Dargie's testimony as Witness Dargie testified that the Commission directive "can have a chilling effect on customer participation in the EE&PDR programs which impacts the Companies' ability to meet their EE&PDR targets."

Without waiving this objection, the Companies do not have documentation responsive to this request. Further answering, since June 1, 2012, in Pennsylvania, 460 out of 1033 customers or 45% of commercial and industrial customers who participated in those programs opted to retain ownership of the EE resource attributes, representing approximately half of the associated projects in energy savings.

Program names, descriptions and rebate forms, including rebate amounts and terminology related to EE resource attribute ownership for current programs are available on FirstEnergy's *Save Energy* Website:
https://www.firstenergycorp.com/content/customer/save_energy.html

The Companies anticipate that the chilling effect may take place on any program where a customer is required to affirmatively assign ownership of an EE Resource as a condition of program participation.

Case No. 12-2190-EL-POR, Case No. 12-2191-EL-POR, Case No. 2192-EL-POR

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric
Illuminating Company, and The Toledo Edison Company For Approval of Their
Energy Efficiency and Peak Demand
Reduction Program Portfolio Plans for 2013 through 2015

RESPONSES TO REQUEST

SC Set 1–
INT-48

Identify how the companies savings assumptions for linear fluorescent retrofits
incorporate recent EISA standards.

Response: The Companies modeled the annual savings of linear fluorescent retrofits according to
Section 3 of the Draft Ohio TRM, including establishing baselines in accordance with 2007
EISA standards. As such, the Companies estimated baseline equipment equivalent to
32W T8 for retrofit to higher efficiency linear fluorescent lighting for purposes of modeling.

Case No. 12-2190-EL-POR, Case No. 12-2191-EL-POR, Case No. 2192-EL-POR

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company For Approval of Their Energy Efficiency and Peak Demand Reduction Program Portfolio Plans for 2013 through 2015.

RESPONSES TO REQUEST

**NRDC Set 3–
INT-31**

Referring to Appendices C-4 of Attachments A, B, and C, do the Companies anticipate providing incentives for Linear Fluorescent Retrofits that change T12 lighting to Standard T8 and T5 lighting?

Response:

Yes, consistent with EM&V protocols as adopted by the Commission, the Companies would incent and claim savings based on as-found conditions for equipment that is replaced as early retirement. This may include T12 lighting to Standard T8 or T5 lighting retrofits.

SC Set 2
Witness: Miller

Case No. 12-2190-EL-POR, Case No. 12-2191-EL-POR, Case No. 2192-EL-POR

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company For Approval of Their Energy Efficiency and Peak Demand Reduction Program Portfolio Plans for 2013 through 2015

RESPONSES TO REQUEST

SC Set 2–
INT-70

The program description for the Demand Response program says that the Companies will now "count demand response resources participating in the PJM market for the applicable delivery year, without the need to contract for these resources separately." How does FirstEnergy justify counting reductions in peak demand from resources participating in PJM capacity market if FirstEnergy has no involvement in those reductions and provided no incentives or payments for those reductions?

Response:

Pursuant to Ohio Administrative Code Chapter 4901:1-39-05(E)(2), an electric utility may satisfy its peak-demand reduction through a peak demand reduction program that meets the requirements to be counted as a capacity resource under the tariff of a regional transmission organization. The Companies are not aware of a specified requirement that a utility needs to offer an incremental program incentive to the resources participating in such a program. Nonetheless, it should be noted that the Companies and their Ohio customers do participate in capacity auctions in the PJM market and therefore do, indirectly, contribute to the PJM payments/incentives for demand resources participating in the PJM market for the applicable delivery year. Additionally, the Companies believe that this approach will help minimize compliance costs with the statutory mandates, and is thus a more cost-effective approach than requiring the Companies to offer an incremental program incentive to these participating resources. Should the Commission order an incremental program incentive be offered, the Companies' proposed program budget and design incorporates that flexibility.

This foregoing document was electronically filed with the Public Utilities

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In

Case No(s). 12-2191-EL-POR, 12-2190-EL-POR, 12-2192-EL-POR

Summary: Testimony of Jeffrey Loiter electronically filed by Mr. Christopher J Allwein on behalf of The Sierra Club



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Environmental
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2009 JUL 31 PM 3:51

DOCUMENT CONTROL

July 31, 2009

VIA ELECTRONIC FILING

The Honorable Joel H. Peck
Office of the Clerk, State Corporation Commission
c/o Document Control Center
P.O. Box 2118
Richmond, Virginia 23218-2118

PUE-2009-00023

RE: RE: Ex Parte: In the matter of determining achievable, cost-effective energy conservation and demand response targets that can realistically be accomplished in the Commonwealth through demand-side management portfolios administered by each generating utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly.

Dear Mr. Peck:

Attached please find the Direct Testimony of Jeff Loiter and William Steinhurst on behalf of the Southern Environmental Law Center, Appalachian Voices, and the Virginia Chapter of the Sierra Club ("Environmental Respondents") for filing in the above-referenced matter, along with the required 15 copies for the Commission. The brief of the Environmental Respondents will be filed today via electronic submission.

Sincerely,

A handwritten signature in black ink that reads "Caleb A. Jaffe".

Caleb A. Jaffe

cc: Parties on Service List
Commission Staff



COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA)
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STATE CORPORATION COMMISSION)
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Ex Parte: In the matter of: determining)
achievable, cost-effective energy)
conservation and demand response targets)
that can realistically be accomplished in the)
Commonwealth through demand-side)
management portfolios administered by)
each generating utility identified by)
Chapters 752 and 855 of the 2009 Acts of)
the Virginia General Assembly)

Case No. PUE-2009-00023

DIRECT TESTIMONY OF JEFF LOITER
ON BEHALF OF THE SOUTHERN ENVIRONMENTAL LAW CENTER, ET AL.

Filed: July 31, 2009

1 Q. Please state your name and business address.

2 A. Jeffrey Loiter, Optimal Energy, Incorporated, 14 School Street, Bristol, VT
3 05443.

4 Q. On whose behalf are you testifying?

5 A. I am testifying on behalf of the Southern Environmental Law Center ("SELC"),
6 the Virginia Chapter of the Sierra Club and Appalachian Voices.

7 Q. Mr. Loiter, by whom are you employed and in what capacity?

8 A. I employed as a Managing Consultant by Optimal Energy, Inc, a consultancy
9 specializing in energy efficiency and utility planning. In this capacity I direct and perform
10 analyses, author reports and presentations, manage staff, and interact with clients to serve
11 their consulting needs.

12 Q. Summarize your qualifications.

13 A. I have 13 years of experience in environmental and economic consulting. For the
14 past 3 years, I have been engaged in a variety of work at Optimal Energy related to
15 energy efficiency program design and analysis. For example, I prepared two documents
16 for inclusion with EPA's *National Action Plan for Energy Efficiency*: a guidebook on
17 conducting efficiency potential studies, and a handbook describing the funding and
18 administration of clean energy funds.¹

19 I have also participated in several studies of efficiency potential and economics,
20 including ones in New York, Vermont, Massachusetts, Texas, and Prince Edward Island.

21 These have ranged from macro-level assessments to extremely detailed, bottom-up

¹ These can be found at http://www.epa.gov/cleanenergy/documents/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

1 assessments evaluating thousands of measures among numerous market segments. A
2 recent example of the latter is an analysis of the electric efficiency potential for Orange &
3 Rockland Utilities in New York State.

4 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
5 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
6 Environmental Engineering from Cornell University and an *M.S.* in Technology and
7 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
8 SELC-JML-1.

9 **Q. Have you previously testified before the Virginia State Corporation Commission**
10 **(“the Commission” or “SCC”)?**

11 **A. No.**

12 **Q: What is purpose of your testimony?**

13 **A:** To respond to the Commission’s order establishing proceeding and setting
14 evidentiary hearing in Case No. PUE 2009-00023. Specifically, I address questions 1, 6,
15 and 7 in this order. In doing so, I also address other important concepts and issues related
16 to DSM programs, potential estimates, and policies.

17 **Q: Are you prepared to offer a response to Question 1: “What is an achievable, cost-**
18 **effective energy conservation and demand response target that can be realistically**
19 **accomplished through the generating electric utility’s demand-side management**
20 **portfolio?”**

21 **A:** Yes, but before doing so I believe several of the key terms in the question must be
22 defined.

23 **Q: Which terms do you believe require definition?**

1 A: The terms “achievable,” “cost-effective,” “conservation,” “demand response,”
2 and “realistically accomplished.”

3 **Q: How do you define these terms?**

4 A: For the terms “achievable,” “cost-effective,” and “realistically accomplished,” I
5 concur with the testimony of William Steinhurst, also on behalf of SELC. Note that in
6 this taxonomy, the potential that can be realistically accomplished is a subset of that
7 which is achievable, which in turn is a subset of that which is cost-effective.

8 For purposes of this case, I believe the term “conservation” is intended to include
9 what most in the DSM community would refer to as “efficiency.” Efficiency means
10 providing the same level of service with less energy. More efficient lighting provides
11 equivalent illumination but saves energy; more efficient HVAC systems provide the same
12 amount of heating or cooling but save energy.² Conservation is a broader term than
13 efficiency, and includes energy reductions that result from reducing level of service, for
14 example by lowering thermostats during the heating season. My testimony is focused
15 mainly on the potential for efficiency-related savings, although I also briefly address
16 other concepts, such as demand response.

17 “Demand response” refers to temporarily reducing energy consumption, typically
18 for purposes of reducing the peak load on the electric system. This usually means
19 reducing level of service, for example by dimming lights, raising cooling setpoints, or
20 reducing production in an industrial facility. Dominion witness Venable seems to confuse
21 demand response with efficiency and/or conservation, noting that “other considerations

² To most DSM practitioners, conservation means using less energy, even if the level of service is reduced. Setting a thermostat at a higher temperature during the summer is conservation, as is choosing to walk to the store instead of driving. In general, advocates of energy efficiency prefer to focus on true efficiency gains, rather than behavioral changes aimed at conservation.

1 related to cost impacts are whether customers will change their lifestyles long-term in
2 order to achieve the level of reductions projected for DSM programs that may be offered
3 to them.”³ Customers who take advantage of DSM programs that encourage investments
4 in more efficient equipment or appliances or that improve the thermal characteristics of
5 their buildings are not required to “change their lifestyles long-term.” This is only
6 relevant to demand response programs, which should be only one component of a
7 comprehensive DSM portfolio.

8 Finally, I wish to clarify that my testimony is focused on the electric system and
9 not on any other fuels which are consumed by end-users and that could be subject to
10 DSM efforts, such as natural gas.

11 **Q: Please clarify your statement regarding “one component of a comprehensive DSM**
12 **portfolio.”**

13 **A:** Demand-side management, at its broadest, includes efficiency, demand response,
14 and other alternatives to central-station energy supply such as distributed generation. The
15 latter includes customer-sited renewables and combined heat and power installations. In
16 this testimony, I will be focusing primarily on efficiency.

17 **Q: What target level of DSM savings can be realistically accomplished in Virginia?**

18 **A:** There is ample evidence that efficiency alone can realistically achieve energy
19 savings of at least 12% of forecast load in 2022, with a reduction in peak demand of
20 greater than 3,900 MW. Demand response can provide additional peak reductions of
21 nearly 1,700 MW. However, I recommend that the Commission set tangible energy

³ Direct Testimony of Shannon L. Venable on behalf of Virginia Electric and Power Company, June 30, 2009, p. 17.

1 savings targets to be met in the next three to five years. My proposed state-wide targets
2 are shown in the table below.

3
4

| Realistically Accomplishable DSM savings in Virginia | | | | |
|--|---------------|-------|---------------|-------|
| | 2013 | | 2022 | |
| | GWh | MW | GWh | MW |
| Efficiency | 3,340 | 724 | 18,192 | 3,942 |
| Demand Response | N/A | 1,136 | N/A | 1,698 |
| CHP | Not Estimated | | Not Estimated | |
| Total | 3,340 | 1,860 | 18,192 | 5,640 |

5
6 **Q: What behavioral changes will Virginians need to make to achieve this level of**
7 **savings?**

8 **A:** As I explained earlier, realizing savings from efficiency investments do not
9 require behavioral changes on the part of consumers. The key change is for consumers to
10 select more efficient lighting, equipment, and building practices. In contrast to some
11 arguments against efficiency programs, the utilities have an important role to play in this
12 change. As described later in my testimony, a wide range of strategies are available to
13 utility-sponsored efficiency programs by which barriers to these investments may be
14 overcome.

15 **Q: Are these savings targets the maximum amount that are available in Virginia?**

16 **A:** No, they are not. As I note later in my testimony, a far larger potential of cost-
17 effective efficiency savings exists in Virginia, likely on the order of 20% of forecast load
18 in a 15 to 20 year time-frame.

19 **Q: Why do you recommend short-term targets?**

1 A: For two reasons. First, setting a target over 10 years in advance can lead to delays
2 in program initiation, based on the belief that near-term shortfalls can be made up later
3 on. Efficiency programs work best with sustained, consistent effort, rather than repeated
4 bursts of intense activity.⁴ Setting clear goals for the next few years will provide the
5 necessary impetus to rapidly develop sustained and consistent efforts. In the meantime,
6 the Commission should consider conducting a detailed potential study that relies on as
7 much up-to-date, state-specific information as possible to inform future decisions.

8 Q: Does that mean a long-term goal is inappropriate?

9 A: No. Setting long-term goals indicates a commitment to sustained energy
10 efficiency efforts, but this should not take the place of short-term targets, for the reasons
11 cited above. Conditions in the marketplace and the economy are constantly changing.
12 Setting short-term targets, preferably backed by appropriate incentives and disincentives,
13 is a prudent policy approach. Ideally, any targets for energy efficiency savings should be
14 expressed as actual MWh and MW goals for each year, set in advance based on the best
15 available short-term forecast.

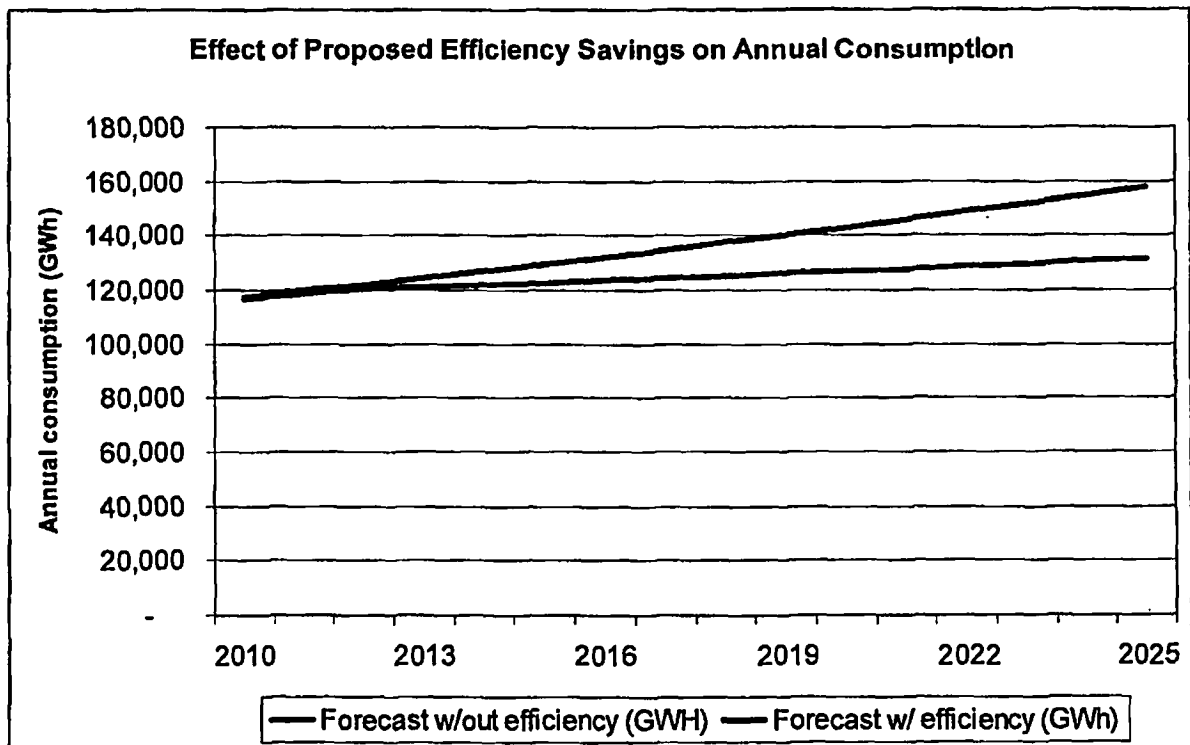
16 Q: What is the basis for your efficiency target?

17 A: As I describe in more detail below, it is reasonable to conclude that Virginia can
18 acquire savings from efficiency of approximately 1.3% of load each year within 4 years
19 of program initiation. Assuming initial savings of 0.25% in 2010 and an increase in this
20 target of 75% each year, annual savings reach 1.3% by 2013 (in the 4th year of
21 implementation) (see table). If savings were to remain at this level, cumulative savings

⁴ Department of Energy and Environmental Protection Agency. *National Action Plan for Energy Efficiency*. July 2006. p. 2-18. Available at http://www.epa.gov/cleanenergy/documents/napee/napee_report.pdf.

1 would be 12.2% of the original forecast consumption in that year, assuming growth of
 2 2% per year. This effect is presented graphically in the figure below.

| Year | Forecast w/out efficiency (GWh) | Savings Target (%) | Incremental Savings (GWh) | Forecast w/ efficiency (GWh) | Reduction from Original Forecast |
|------|---------------------------------|--------------------|---------------------------|------------------------------|----------------------------------|
| 2010 | 117,351 | 0.25% | 293 | 117,058 | 0.3% |
| 2011 | 119,698 | 0.44% | 522 | 118,876 | 0.7% |
| 2012 | 122,092 | 0.77% | 928 | 120,326 | 1.4% |
| 2013 | 124,534 | 1.30% | 1,596 | 121,137 | 2.7% |
| 2014 | 127,024 | 1.30% | 1,606 | 121,953 | 3.9% |
| 2015 | 129,565 | 1.30% | 1,617 | 122,775 | 5.1% |
| 2016 | 132,156 | 1.30% | 1,628 | 123,603 | 6.2% |
| 2017 | 134,799 | 1.30% | 1,639 | 124,436 | 7.3% |
| 2018 | 137,495 | 1.30% | 1,650 | 125,274 | 8.3% |
| 2019 | 140,245 | 1.30% | 1,661 | 126,119 | 9.4% |
| 2020 | 143,050 | 1.30% | 1,672 | 126,969 | 10.4% |
| 2021 | 145,911 | 1.30% | 1,684 | 127,824 | 11.3% |
| 2022 | 148,829 | 1.30% | 1,695 | 128,686 | 12.2% |
| 2023 | 151,806 | 1.30% | 1,706 | 129,553 | 13.1% |
| 2024 | 154,842 | 1.30% | 1,718 | 130,427 | 14.0% |
| 2025 | 157,939 | 1.30% | 1,729 | 131,306 | 14.8% |



1 **Q: On what do you base the conclusion that 4 years is sufficient to reach your suggested**
2 **target savings level of 1.3% per year?**

3 A: Even utilities that are new to DSM can ramp up programs quickly to substantial
4 impacts. For example, in 2007, the third year of its DSM program, the Arizona Public
5 Service Company achieved annual energy savings equivalent to 0.9% of retail electricity
6 sales, after savings of 0.1% in 2005 and 0.4% in 2006).⁵ Austin Energy (Texas) increased
7 their savings from 0.6% in 2004 to 1.1% in 2005. Burlington Electric Department
8 (Vermont) grew their savings from just under 1% in 2004 to 2.5% in 2007.⁶

9 **Q: How does this estimate compare with others estimates prepared by Dominion**
10 **Power, ACEEE, and others?**

11 A: Care must be taken when comparing multi-year savings estimates to ensure that
12 the estimates are in fact truly comparable. For example, the suggested target from HB
13 3068 of 10% savings, which Dominion has affirmed as realistically accomplishable,⁷ is
14 in reference to 2006 consumption. On the other hand, the “medium case” potential
15 estimated by ACEEE in 2008⁸, as supported by the Governor’s Commission on Climate
16 Change, is in reference to *forecast* consumption in 2025. This complicates matters,
17 because electric consumption is generally growing. The same amount of energy (as
18 measured in kWh) will represent a larger percentage of 2006 consumption than of 2025
19 consumption. The table below adjusts these differences in basis year using a 2% annual

⁵ Arizona Public Service Company's response to Western Resource Advocates First Set of Data Requests, Arizona Corporation Commission Docket No. E-01345A-08-0172, August 4, 2008.

⁶ Data from EIA Form 861 database, <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>, accessed July 22, 2009.

⁷ Venable testimony, p. 4.

⁸ ACEEE et al, *Energizing Virginia: Energy First*, Report No. E085, September, 2008. page 24

1 growth rate in electricity consumption and compares the results for a common year,
2 2022.⁹

3 In addition, the ACEEE estimate included savings from some federal appliance
4 standards that will occur regardless of utility action, and some savings from CHP.

5 Finally, program “ramp-up” in early years is often not explicitly considered in long-term
6 studies. Adjusting for these factors yields the following comparison. Note that the second
7 row in this table corresponds to the 19% “medium case” estimate often cited from the
8 ACEEE report.

9

⁹ ACEEE used a compound annual growth rate of 1.4% per year through 2025, based on information from EIA data. Dominion presented a rate of 2.39% per year through 2024 in testimony by Ms. Venable, p. 24. For simplicity, and to account for potential differences by utility service area, I assume a rate of 2% per year.

1

| Source | Implied average annual incremental efficiency savings | Reduction from 2022 forecast consumption |
|---|---|--|
| H 3068 "10% target," assuming ALL from efficiency | 0.7% | 7.8% |
| ACEEE medium case, less federal appliance standards and CHP | 1.2% | 12.9% |
| ACEEE high case, less federal appliance standards and CHP | 1.8% | 18.6% |
| This testimony, assuming ramp-up to 1.3% per year | 1.1% | 12.2% |

2

3 **Q: What effect would savings equal to your suggested efficiency target have on peak**
 4 **system load?**

5 **A:** Using the simplifying assumption that efficiency investments reduce peak load by
 6 the same percentage as they do energy, the table above shows a reduction of over 3,900
 7 MW by 2022.

8 **Q: Does this reduction in peak load include reductions from demand response?**

9 **A:** No, demand response savings would provide *additional* peak demand reductions,
 10 but little to no additional energy savings. While reducing peak demand is an important
 11 goal for Virginia, energy efficiency savings should be the primary objective, with
 12 additional and separate goals for DR. Note that investments that save energy also reduce
 13 peak demand, and continue to do so for several years, depending on the life of the
 14 measure. The converse is not true; many strategies for reducing peak demand result in
 15 little to no energy savings (e.g., real-time demand response, peak-period pricing, load
 16 shifting technologies including operations schedule changes, etc), and further must be

1 acquired (and paid for) each and every year. SELC witness Steinhurst discusses the
2 difference between demand response and efficiency in greater detail.

3 **Q: What is the basis of your conclusion that Virginia can reach savings of 1.3% per**
4 **year from efficiency?**

5 **A: The proposed savings target is based on review and analysis of actual DSM**
6 **program experience in North America over the past few decades, as well as several**
7 **potential studies, including the previously cited study conducted for Virginia by ACEEE.**

8 **Q: Please summarize the DSM program experience that forms the basis of your**
9 **opinion.**

10 **A: Numerous jurisdictions have implemented DSM energy efficiency portfolios that**
11 **have saved over 0.9% per year, including in Iowa, California, Connecticut, Minnesota**
12 **and South Carolina, as shown in the table below.¹⁰ Not shown on this table is Efficiency**
13 **Vermont (Vermont's "energy efficiency utility"), which has traditionally saved about 1%**
14 **of load statewide per year. In 2006 the VT Public Service Board increased Efficiency**
15 **Vermont's budgets and goals, resulting in the need for Efficiency Vermont to increase**
16 **savings to 2.5%, which they achieved in 2008.¹¹ Moreover, in narrowly targeted**
17 **programs to transmission-constrained geographic areas Efficiency Vermont was able to**
18 **capture 4.5% in 2008.¹²**

¹⁰ This table presents results from all utilities who saved 0.9% or greater in 2007, the latest year for which data are available. Data from EIA Form 861 database, <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>, accessed July 22, 2009.

¹¹ Efficiency Vermont Preliminary 2008 Annual Report, March 2009.

¹² Geotargeted area savings and load data provided by Efficiency Vermont.

2007 Efficiency Program Savings

| Utility | State | EE Spending as % of Total Revenue | Incremental MWh Savings as % of Total Retail Sales |
|--------------------------------|-------|-----------------------------------|--|
| City of Breckenridge | MN | 1.3% | 3.5% |
| Glidden Rural Electric Coop | IA | 1.2% | 2.6% |
| Burlington City of | VT | 2.0% | 2.5% |
| Pacific Gas & Electric Co | CA | 3.1% | 2.1% |
| City of Windom | MN | 1.4% | 2.1% |
| Southern California Edison Co | CA | 3.6% | 2.0% |
| Connecticut Light & Power Co | CT | 2.2% | 1.8% |
| Massachusetts Electric Co | MA | 2.4% | 1.6% |
| United Illuminating Co | CT | 2.9% | 1.5% |
| Laurens Electric Corp, Inc | SC | 3.1% | 1.3% |
| Western Massachusetts Elec Co | MA | 1.6% | 1.2% |
| Rochester Public Utilities | MN | 1.3% | 1.2% |
| Merced Irrigation District | CA | 1.1% | 1.1% |
| Fitchburg Gas & Elec Light Co | NH | 1.7% | 1.1% |
| Eugene City of | OR | 3.0% | 1.0% |
| Reedy Creek Improvement Dist | FL | 0.2% | 1.0% |
| Narragansett Electric Co | RI | 1.9% | 1.0% |
| Arizona Public Service Co | AZ | 0.7% | 0.9% |
| Snohomish County PUD No 1 | WA | 1.7% | 0.9% |
| Sacramento Municipal Util Dist | CA | 2.1% | 0.9% |
| Madison Gas & Electric Co | WI | 0.8% | 0.9% |

1

2 **Q: Should these programs be considered anomalies?**

3 **A:** No, these jurisdictions have simply made a commitment to achieving substantial
 4 energy efficiency savings. Numerous states have recently established goals of 1% per
 5 year or more, affirming the belief that these levels are realistically accomplishable. New
 6 York has set a goal to capture a 15% reduction in electric usage from efficiency by 2015
 7 (approximately 1.9% per year).¹³ Pacific Gas and Electric (PG&E) has previously
 8 acquired approximately 1% per year and is planning to increase this to between 1.4 and
 9 1.6% per year.¹⁴ Illinois has set a goal to gradually increase savings to 1% per year after 5

¹³ NY Public Service Commission, *Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard*, Case 07-M-0548, 16 May 2007.

¹⁴ Direct testimony of John J. Plunkett, Docket No. 070098-EI, before the Public Service Commission of Florida, 2007.

1 years and 2% per year after 10 years.¹⁵ Massachusetts and Connecticut are both
2 considering dramatic ramp-up of existing efficiency efforts that would bring savings up
3 to over 2% of load each year.¹⁶ Massachusetts has also articulated a goal of eliminating
4 all load growth by efficiency investment for the indefinite future. The table below
5 presents current goals for a number of leading states, many with little or no prior DSM
6 history.

¹⁵ Illinois Power Agency Act (SB 1592), enacted August 2007.

¹⁶ Massachusetts Department of Telecommunications and Energy, *Petition of the Massachusetts Division of Energy Resources For An Investigation into Establishing an Electricity Performance Standard as a Component of the Supply of Basic Service Electricity*, Dec. 21, 2006, p.34 and *Conservation and Load Management Portfolio Plan, Docket 06-10-02, Scenario 2 Supplemental Filing*, January 24, 2007, submitted to the DPUC jointly by Connecticut Light and Power Company and United Illuminating Company.

| State | Year | Target | Year | Target |
|-----------------------------|------|---|------|--------|
| Texas | 2007 | 20% of load growth | 2010 | 0.5% |
| Vermont | 2008 | 2.0% per year (contract goals) | 2011 | 2.0% |
| California | 2004 | EE is first resource to meet future electric needs ^{1,9} | 2013 | 2.0% + |
| Hawaii | 2004 | .4% - .6% per year ² | 2020 | 0.5% |
| Pennsylvania | 2008 | 3.0% of 2009-2010 load | 2013 | 0.8% |
| Connecticut | 2007 | All Achievable Cost Effective ^{3,9} | 2018 | 2.0% + |
| Nevada | 2005 | 0.6% of 2006 annually ⁴ | n/a | 0.6% |
| Washington | 2006 | All Achievable Cost Effective ⁹ | 2025 | 2.0% + |
| Colorado | 2007 | 1.0% per year | 2020 | 1.0% |
| Minnesota (elec & gas) | 2007 | 1.5% per year | 2010 | 1.5% |
| Virginia | 2007 | 10% of 2006 load | 2022 | 0.7% |
| Illinois | 2007 | 2.0% per year | 2015 | 2.0% |
| North Carolina | 2007 | 5% of load ⁵ | 2018 | 0.4% |
| New York (electric) | 2008 | 10.5% of 2015 load ⁶ | 2015 | 1.5% |
| New York (gas) | 2009 | 15% of 2020 load ⁶ | 2020 | 1.4% |
| New Mexico | 2009 | All achievable cost-effective, minimum 10% of 2005 load | 2020 | 1.0% + |
| Maryland | 2008 | 15% of 2007 per capita load ⁷ | 2015 | 3.3% |
| Ohio | 2008 | 2.0% per year | 2019 | 2.0% |
| Michigan (electric) | 2008 | 1.0% per year | 2012 | 1.0% |
| Michigan (gas) | 2008 | 0.75% per year | 2012 | 0.8% |
| Iowa (electric) | 2009 | 1.5% per year | 2010 | 1.5% |
| Iowa (gas) | 2009 | 0.85% per year | 2013 | 0.3% |
| Massachusetts | 2008 | All Achievable Cost Effective ⁹ | | 2.0% + |
| New Jersey (electric & gas) | 2008 | 20% of 2020 load ⁸ | 2020 | ≤2.0% |
| Rhode Island | 2008 | All Achievable Cost Effective ⁹ | | 2.0% + |

Source: ACEEE, Laying the Foundation for Implementing a Federal Energy Efficiency Standard, March 2009, report no. E091.

Notes:

- * Implied annual reduction for targets based on current year loads assumes average underlying load growth (not accounting for EE) of 1.5% per year. Texas based on recent load growth of 3%/yr.
- 1 CA programs exceeded 1.5%/yr. in 2007. While current mandated goals are lower, CA policy requires investment in efficiency whenever it is less costly than alternative new supply.
- 2 HI established a renewable portfolio standard that includes efficiency as a resource and requires 20% savings by 2020, or approximately 2.8%/yr. However, this can come from efficiency or renewable resources. Current efficiency savings has ranged from 0.4% - 0.6%/yr.
- 3 CT requires capture of all available cost-effective efficiency resources. Current utility plans reflect goals of about 1.5%/yr.
- 4 NV has an RPS requiring 15-20% of load and allows EE to meet 25% of the goal. Utilities are ramping up to meet the maximum level of 5% of load from efficiency. Figure reflects 2008 program achievements.
- 5 NC RPS ramps up to 12.5% of load in 2021, with EE capped at 40% of this target, or 5%.
- 6 NY established a 15% savings goal (July 2008) for electric efficiency by 2015, however this includes an estimated 4.5% savings from codes & standards. Electric figure is for efficiency programs only. NY just established a 14.7% goal for gas efficiency by 2020. However, it is unclear whether this includes any savings that might come from codes & standards.
- 7 MD goal is set as a reduction off of 2007 per capita load. Implied annual goal assumes underlying load growth per capita (net of efficiency programs) of 0.75%.
- 8 NJ legislature recently authorized the BPU to set electric and gas goals of 20% savings each by 2020. Goals still under development.
- 9 CA, CT, MA, RI require all achievable cost effectiveness. This is shown as 2.0% + because recent studies indicate the potential is at least 2%. MA is currently discussing goals between 2-3% for electric programs.

1

2 Q. Does the fact that most of these states have been leaders in DSM for a long time and
 3 that Virginia has relatively little experience in DSM efforts imply that it is not
 4 realistic or achievable for Virginia to meet goals similar to other states?

1 A. No. Although Virginia is unique in many respects, there is no reasonable basis to
2 conclude that Virginia would be unable to join the ranks of the leading efficiency states
3 noted above, for several reasons. First, the marketplace for efficient energy consuming
4 systems is a national market. Efficient lighting systems, HVAC units, motors and other
5 equipment that are available throughout the United States are available to Virginians, too.
6 The opportunities to reduce electricity consumption are as ample in Virginia as they are
7 in, for example, Connecticut.

8 Second, Virginia's climate does not impose constraints on the potential for
9 efficiency savings and may, in fact, offer additional opportunities. Although cooling
10 savings as a percent of total cooling energy do not change dramatically with climate, the
11 total energy saved by cooling measures is greater in hotter climates. Several utilities in
12 hotter climates are among the top efficiency programs, including Austin Energy (TX),
13 Gainesville Regional Utilities (FL), and Nevada Power Company. Therefore, cooling
14 measures are likely to be more cost-effective in Virginia than in cooler climates and may
15 represent a greater share of overall savings. Furthermore, Appalachian Power Company
16 is a winter-peaking utility and Dominion Power's winter peak is nearly as great as their
17 summer peak, indicating substantial electric heat load throughout the state. Efficiency
18 measures that improve the ability of the building envelope to maintain conditioning (i.e.,
19 insulation and air sealing) will therefore be more cost-effective than in colder climates
20 where electric heating is less prevalent, because they save electricity year-round rather
21 than just during the cooling season.

22 Third, historically low retail electric rates mean Virginians have had less
23 economic incentive to invest in efficiency opportunities on their own. This, combined

1 with the near-complete lack of significant DSM efforts in Virginia, should result in there
2 being far more opportunities for untapped efficiency (i.e., those that have not occurred
3 naturally in the marketplace) than in other jurisdictions that have been capturing
4 substantial efficiency savings for as long as two decades.

5 Last, I note that the ACEEE report indicates that per customer electric usage has
6 increased substantially over the past 10 years. According to the report, Virginia residents
7 consume on average 14,000 kWh annually, which is 25% more than the national
8 average. Commercial customers now consume 50% more than they did in 1990.¹⁷ These
9 facts alone indicate to me that there is a massive untapped reservoir of readily accessible
10 and inexpensive energy that could be acquired by Virginia's electric distribution utilities.
11 Unless Virginia's utilities presume that their customers are somehow less capable of
12 participating in well designed efficiency programs than other US citizens, the only real
13 difference that sets Virginia apart from the leading states is the level (or lack) of market
14 intervention in which Virginia chooses to engage. Consequently, Virginians are just as
15 likely to invest wisely and curb their electric consumption if provided with appropriate,
16 well-designed, and attractive programs like those provided by other leading states...

17 **Q: What about differences in the cost of electricity? Does that affect the relevance of**
18 **the DSM experience in other areas to the available efficiency potential in Virginia?**

19 **A:** Yes, but only to a limited degree. First, it is important to distinguish between the
20 retail cost of electricity and the value of avoiding the consumption of an additional
21 kilowatt-hour of electricity (i.e., 'avoided costs'). Retail electric rates are a function of a
22 utility's previous spending on infrastructure, their costs of operation (including fuel for

¹⁷ ACEEE 2008, page 1.

1 generation), and an allowed return on their investments. Retail rates can be structured in a
2 variety of ways, and are commonly different for different types of consumers. Avoided
3 costs take into account the costs associated with building new infrastructure to meet
4 growing demand and likely future operational costs. While Virginia has had lower retail
5 electricity costs than the leading jurisdictions in efficiency, I note that the two largest
6 utilities have recently filed for substantial rate increases. In addition, avoided costs are
7 typically based on the cost of new supply and are not dramatically different than in many
8 other areas pursuing DSM. For example, the recently approved Wise County Coal Plant
9 being built by Dominion is estimated to have an all-in cost of 9.3 cents/kWh.¹⁸ Add to
10 this the avoided costs of transmission and distribution, and it is clear that avoided costs in
11 Virginia will not significantly limit efficiency potential. Finally, I note that Idaho,
12 Washington, and Oregon, states with historically low energy costs, are in the top third of
13 U.S. states in terms of annual energy efficiency savings.

14 In addition, DSM opportunities are generally highly cost-effective when
15 compared to traditional supply options. For example, most DSM efforts tend to provide
16 savings at a cost of between two and four cents per kWh, well below any reasonable
17 avoided cost estimate for Virginia.¹⁹ Therefore, while avoided costs do have some
18 influence on the efficiency potential, it is typically fairly small, and mostly relevant when
19 considering the maximum cost-effective potential in a particular area. While differences
20 in climate, avoided costs, retail electric rates and demographics have some impact, they
21 are relatively small in terms of the percentage of load that can be saved and do not

¹⁸ Final Order, Case No. PUE-2007-00066, State Corporation Commission, 31 March 2008, p. 12.

¹⁹ National Action Plan for Energy Efficiency, p. 1-6.

1 materially affect whether Virginians are able to reduce electricity consumption by the
2 targets I have proposed.

3 **Q: Earlier you referred to a review of potential studies as contributing to your**
4 **developing the savings target. Can you expand on that?**

5 A. Yes, as noted earlier, I reviewed several potential studies, including the study
6 performed by ACEEE for Virginia. I have conducted potential studies myself and have
7 reviewed many others, so I am familiar with the methods used and the results in general.
8 In addition, I was recently a lead author on the U.S. EPA's *Guide to Conducting Energy*
9 *Efficiency Potential Studies* as part of its National Action Plan for Energy Efficiency.²⁰

10 More specifically, I have reviewed the recent study done for Virginia by ACEEE
11 In addition, this study was supplemented by consideration of other studies done for areas
12 in the Southeast region, including in Georgia and North Carolina, and the nationwide
13 potential study sponsored by EPRI.

14 **Q: What do you conclude from review of the ACEEE study?**

15 A: The ACEEE study presents a reasonable macro-level assessment of the potential
16 for energy efficiency and demand response to reduce the need for centrally-generated
17 electric supply to meet the needs of Virginia's consumers. It is based on well-known data
18 sources such as the Energy Information Administration, PJM Interconnection, and the
19 Lawrence Berkeley National Laboratory. The study appears to use methods that
20 generated reasonable and supportable estimates of efficiency potential. The study
21 accounted for naturally occurring efficiency actions over its analysis period, and
22 separately estimated potential efficiency opportunities from codes and standards as well

²⁰ http://www.epa.gov/cleanenergy/documents/potential_guide.pdf

1 as utility programs. The study also accounted for reduced savings from the interaction of
2 multiple efficiency measures.²¹ The avoided costs used in the study were between 6 and 7
3 cents per kWh through 2023, which are conservative given the forecast costs of the Wise
4 Co. plant.

5 **Q: What were the results of the ACEEE study?**

6 **A:** The table below summarizes the three scenarios of achievable energy savings as
7 presented in the study.

| | Low | Medium | High |
|-----------------------------------|------|--------|------|
| Total savings in 2025 | 12% | 19% | 27% |
| <i>Mandated federal standards</i> | 3.3% | 3.3% | 3.3% |
| <i>CHP</i> | 0% | 1.0% | 2.7% |
| Efficiency savings in 2025 | 8.3% | 15% | 21% |

8
9
10 **Q: Are the results of the ACEEE study reasonable when compared with other studies?**

11 **A:** Yes. Efficiency potential assessments commonly find achievable savings potential
12 in excess of 20% over study periods ranging from 10 to 20 years, as shown in the table
13 below.

²¹ For example, reducing the energy needed for lighting also reduces the energy needed for cooling, particularly in commercial buildings. This in turn reduces the savings that can be realized from more efficient cooling equipment.

| Electric Efficiency Potential | | | | | | | | |
|-------------------------------|------|-----------------|-------------------------|------------------------|------------------------|------------------------|-------------|--|
| State | Year | Planning Period | Unconstrained Potential | Conservative Potential | Conservative Potential | Conservative Potential | Study | Notes |
| Connecticut | 2009 | 10 | 36.4% | 33.1% | 22.5% | 2.3% | KEMA | Draft. Total achievable estimated at 31% including codes & standards. |
| Maine | 2002 | 10 | N/A | 18.0% | 14.0% | 1.4% | Exeter/ OEI | Simplified analysis based on prior utility data. Did not include low income retrofit (early retirement) nor all new construction markets. |
| Maryland | 2008 | 17 | N/A | N/A | 29.0% | 1.7% | ACEEE | |
| Mass (Nstar only) | 2007 | 10 | N/A | N/A | 17.9% | 1.8% | OEI | High level analysis, electric efficiency only figure. With CHP estimate is 21.1%. |
| Massachusetts | 2001 | 5 | N/A | 24.0% | N/A | | RLW | |
| Mid-Atlantic (NY/NJ/PA) | 1997 | 14 | N/A | N/A | 37.0% | 2.6% | ACEEE | Represents approximate weighted average of sector-specific estimates of 35% Residential, 35% Commercial and 41% Industrial. |
| New England | 2004 | 10 | | | 23.0% | 2.3% | OEI | Meta-analysis for NEEP. Older relatively low CT and ME estimates drove result down. CT study was also assumed to apply to RI. More recent CT and RI studies would have resulted in significantly higher estimate. |
| New Hampshire | 2009 | 10 | 27.6% | N/A | 22.7% | 2.3% | GDS | Ignored most retrofit (early retirement) savings, so viewed as substantially low. |
| New Jersey | 2003 | 17 | N/A | 17.0% | N/A | | KEMA | |
| New York | 2003 | 20 | 35.1% | 32.7% | N/A | N/A | OEI | Forthcoming update with achievable potential has initially estimated about 18% over 7 years, or approximately 2.5%/yr. Still in draft. |
| Rhode Island | 2008 | 10 | 28.0% | 24.0% | N/A | | KEMA | Phase 1 high level study. Detailed study forthcoming in 2009. |
| Vermont | 2003 | 10 | N/A | 38.4% | 30.7% | 3.1% | OEI | |
| Vermont | 2007 | 10 | 34.6% | N/A | 22.0% | 2.2% | GDS | Constrained analysis to 50% of incremental cost incentive levels. For some markets, estimate of achievable was already being exceeded by Efficiency VT at the time of the study. In 2008 EVT achieved 2.5% savings statewide and 4.5% in geotargetted areas (unevaluated results). |
| Averages | | 11.8 | 32.3% | 26.8% | 24.3% | 2.18% | | Mean of data available. |

* "Achievable potential" definitions can vary significantly. In some cases this is estimated as the maximum amount of EE that can be achieved from programs, with no constraints. However, many studies only analyze what could be achieved for a particular set of programs, incentive levels, or budget or rate impact constraints. In addition, some studies exclude some major EE markets completely. For example, some studies have excluded new construction, industrial process, early retirement, fuel switching, or other major opportunities. As a result, these figures should generally be viewed as conservative estimates. Finally, none of the these studies any savings from CHP.

** Average Annual Achievable represents the total estimated achievable potential percent divided by the planning period.

1

2 **Q: Does the ACEEE study represent the maximum possible savings that could be**
 3 **realized from efficiency in Virginia?**

4 **A: No. Many energy analysts believe that virtually all studies tend to produce**
 5 **conservative (i.e., low) estimates of potential for a variety of reasons. There are many**
 6 **reasons why studies tend to under-estimate potential. Some of the major biases, all of**
 7 **which apply to the ACEEE study, include:**

- 1 ▪ Ignoring technology advancement: the ACEEE did not include emerging
2 technologies (p. 9)
- 3 ▪ Exclusion of some avoided costs or benefits, such as the cost of complying with
4 potential carbon regulations: the ACEEE report used simplified avoided costs and
5 did not include carbon costs, resulting costs that “should be viewed as
6 unrealistically low” (p. 11)
- 7 ▪ Exclusion of 100% of the opportunities from any measure that is not cost-
8 effective *on average*. ACEEE screened out non-cost effective measures the sector
9 level, despite the fact that programs can promote and capture savings from these
10 measures from the many individual customers for whom they are cost-effective
11 (pp. 13-15)
- 12 ▪ Assuming zero potential for any sector, segment, market or category of
13 opportunities that are not analyzed. The ACEEE report did not assess potential in
14 agriculture, mining, and construction sectors (p. 17).

15 In addition, one should not view efficiency potential as a finite amount that goes
16 away once captured. Indeed, experience has shown that technologies have generally at
17 least kept pace with past improvements in codes and standards, public efficiency program
18 investments, and naturally adopted efficiency. For example, ACEEE estimated the
19 electric efficiency economic potential in New York State in 1989 to be 29% of forecast
20 load. After roughly 15 years of relatively aggressive DSM programs in New York, a new
21 study in 2003 led by Optimal Energy, along with ACEEE, coincidentally estimated
22 almost exactly the same (30%) amount of efficiency as the economic potential. In short,
23 efficiency opportunities never truly go away because of both ongoing technology

1 advancement and new opportunities that arise from new or expanding applications for
2 electricity use (e.g., data centers, home electronics).

3 **Q: Are you aware of any criticisms of the ACEEE report?**

4 **A: Yes. I have reviewed the comments of Dominion Witness Shannon Venable**
5 regarding the ACEEE study, but find these criticisms unwarranted and not supportive of
6 the contention that ACEEE's findings are "overly ambitious."²² Ms. Venable correctly
7 notes that ACEEE relied on a comparison between the cost of saved energy and the retail
8 price of electricity to determine an efficiency measure's cost-effectiveness, but failed to
9 note that the retail price used was specific to each customer sector (i.e., residential,
10 commercial or industrial), not a uniform 10 cents per kWh (the rate for the residential
11 sector). The relevant rates for the commercial and industrial sectors are 8.9 and 6.8 cents,
12 respectively. Venable correctly notes that this approach to cost-effectiveness is not an
13 indicator of the value to the utility or ratepayers who are not participants in the programs.
14 I agree, and would have preferred that ACEEE use a total resource cost test (TRC), as
15 APCO witness Mr. Castle has advocated,²³ or the adjusted TRC that SELC Witness
16 Steinhurst recommends. However, these retail rates are in fact likely to be LOWER than
17 Virginia avoided costs, as discussed above. As a result, it is unlikely that using the TRC
18 test to screen efficiency measures would reduce ACEEE's estimate of efficiency
19 potential. The ACEEE report does present program cost-effectiveness information using
20 the Total Resource Cost test in Table 15, for their "medium" case.

²² Direct Testimony of Shannon L Venable on behalf of Virginia Electric and Power Company, June 30, 2009, p. 7.

²³ Direct Testimony of William on behalf of Appalachian Power Company, June 30, 2009, p. 13.

1 Ms. Venable also states that she is “unsure”²⁴ as to whether the ACEEE report
2 accounted for program administrative costs. In fact, the analysis does include those costs,
3 as described on page 33. The ACEEE report also presents not one, but three scenarios in
4 its “policy analysis.”

5 **Have you made an estimate of the potential peak reduction from demand response?**

6 A: I have not made an independent estimate of this potential, but have reviewed two
7 sources that did: the ACEEE study previously referenced and a report prepared for the
8 Federal Energy Regulatory Commission that assessed the potential for demand response
9 in each state.²⁵

10 **Q: What did these studies find?**

11 A: Both studies found substantial peak reduction potential from demand response.
12 The FERC study defined three scenarios for demand response beyond that which would
13 be expected in a “business-as-usual” base case. The incremental peak reductions in 2019
14 for Virginia for the three scenarios are 5.2%, 10.2%, and 15.3%. Much of the potential
15 for the lowest scenario would be achieved within a few years. The ACEEE study found
16 similar peak reductions of 4.2%, 7.2%, and 10.8% by 2020. Based on these findings, I
17 conclude that a 4% peak reduction can be realistically accomplished by 2013 and 5% by
18 2022.

19 **Q: Does your suggested target include savings from combined heat and power?**

20 A: No.

21 **Q: Did you review any other studies relevant to this proceeding?**

²⁴ Venable testimony, p. 7.

²⁵ *A National Assessment of Demand Response Potential*. Prepared for the Federal Energy Regulatory Commission by The Brattle Group, Freeman, Sullivan & Co, and Global Energy Partners, LLC. June 2009.

1 A: Yes, I reviewed a study conducted for the Georgia Environmental Facilities
2 Authority (GEFA) in 2005 by ICF Consulting²⁶ and a study for the North Carolina
3 Utilities Commission in 2006 by GDS Associates.²⁷ I have also reviewed the nation-wide
4 potential study conducted by EPRI and cited in testimony by Dominion witness Venable
5 as supporting the “10 percent goal.”²⁸

6 **Q: What do you conclude from your review of the ICF study?**

7 A: The ICF study for Georgia found an achievable potential under a *moderately*
8 *aggressive* (i.e., less than total achievable) scenario of 6% over 5 years, or approximately
9 1.2% per year assuming no ramp up. This is comparable with my recommendation and
10 the findings of the ACEEE study. The study states that it considered a wide range of
11 efficiency measures across all consumer sectors. The reported benefit-cost ratios for the
12 moderately aggressive scenario are surprisingly low, particularly for lighting. On the
13 other hand, cooling measures appear far more cost-effective. This may indicate that much
14 of the benefit of efficiency measures in this model come from reductions in peak demand
15 or on-peak energy, rather than off-peak energy. It may also indicate conservatism in the
16 energy savings estimates or avoided costs. Regardless, the study concluded that “the
17 potential for increased energy efficiency in Georgia is large, with a wide range of
18 associated positive impacts on the economy and environment” (p. 5-9).

19 **Q: What do you conclude from your review of the GDS study for North Carolina?**

²⁶ ICF Consulting. *Assessment of Energy Efficiency Potential in Georgia: Final Report*. Prepared for Georgia Environmental Facilities Authority. 5 May 2005.

²⁷ GDS Associates. *A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina*. Report for the North Carolina Utilities Commission. December 2006.

²⁸ EPRI. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030)*. January 2009.

1 A: The GDS study finds 14 % “achievable cost-effective” potential in a ten-year
2 study period (2008-2017), or approximately 1.4% per year assuming no ramp up. These
3 results should be considered highly conservative, because the study considers an
4 efficiency measure to be cost-effective if it has a levelized cost of saved energy of less
5 than 5 cents per kWh (\$0.05/kWh). This is well below the likely avoided costs in
6 Virginia, but the authors give no justification for this assumption. Although the report
7 provides relatively little detail on its methodology, it appears to be a reasonable macro-
8 level estimate of the potential in neighboring North Carolina whose results are
9 comparable to those of other, more detailed studies.

10 **Q: What do you conclude from your review of the EPRI potential study?**

11 A: The EPRI study presents an unrealistically low estimate of potential for a variety
12 of reasons, the most important of which are enumerated below.

- 13 ▪ The study excludes all early retirement (i.e., “retrofit”) measures, stating that
14 “Consumers or firms that initiate such replacements could be considered
15 predisposed to efficiency or conservation, and their actions may be grouped in the
16 category of market-driven or “naturally-occurring” savings if they would occur
17 independent of an energy efficiency program.” This statement completely ignores
18 years of program experience that demonstrate customers respond to actions and
19 incentives that reduce barriers to efficiency investments. Excluding retrofit
20 measures likely reduces the estimated potential by half to two-thirds.
- 21 ▪ The study relies on the Participant Test to assess cost-effectiveness. This is
22 problematic and likely underestimates the achievable potential: because most
23 customers pay a flat per kWh rate for energy, the participant test will under-

1 estimate the benefits of measures that save expensive on-peak energy, particularly
2 those related to space cooling. Furthermore, the participant test likely does not
3 include the benefits of avoided demand, further under-estimating the benefits of
4 peak-reducing measures. SELC Witness Steinhurst discusses cost-effectiveness
5 testing in more detail.

- 6 ■ Several significant end uses appear to be missing, such as compressed air and
7 commercial cooking, as well as synergistic program delivery options. The
8 analysis of industrial efficiency potential is limited to four end uses, and would
9 appear to significantly understate this sector's potential by exclusion. The premise
10 that the industrial sector is too diverse to allow ready generalization is not an
11 excuse to overlook it.

12 **Q: You have presented information on efficiency potential from a variety of sources,**
13 **including potential studies, the accomplishments of existing DSM programs, and**
14 **targets set by other jurisdictions. Please explain your response to Question 1 in light**
15 **of this information.**

16 **A: Using all of the information described above, it is clear that efficiency savings of**
17 **1.3% per year can be realistically accomplished after an initial ramp-up period. First,**
18 **actual experience in several jurisdictions confirms that this is possible. Second, many**
19 **potential studies indicate potential of at least this level over periods ranging from 5 to 20**
20 **years, and there is evidence that potential studies are often conservative. Third, public**
21 **utility commissions, legislatures, and executive officers in a wide range of jurisdictions**
22 **have confirmed commitments to targets equal to or greater than this level, indicating a**
23 **general consensus regarding the feasibility of such targets.**

1 Overall, current experience and recent goals established elsewhere indicate that
2 the achievable potential for efficiency savings is likely to be in excess of 2% per year.
3 Acquiring savings of this level would require a very high level of commitment from all
4 stakeholders, including the utilities, the State Corporation Commission, ratepayers from
5 all sectors, and the legislative and executive branches. Because I have not examined the
6 specific barriers to efficiency that may influence the efficiency potential that can be
7 realistically accomplished (as that term is described by SELC Witness Steinhurst) I am
8 recommending a more modest target that can be realistically accomplished, including a
9 multi-year period to allow for gradually increasing program efforts to target of 1.3% per
10 year. Furthermore, I suggest that the Commission undertake a more detailed analysis to
11 more precisely estimate the nature and magnitude of the long-term potential in Virginia.
12 Doing so would provide greater assurance that efficiency goals in range of 2% per year
13 are achievable.

14 **Q: Would the existence of “opt-out” provisions such as those in currently exempting**
15 **users with demand greater than 10 MW from paying for DSM programs cause you**
16 **to revise your conclusions?**

17 **A:** No, not materially. Clearly, if a certain class of customer is automatically
18 exempted from paying from DSM programs, one would expect that they would not be
19 eligible for program services. In any case, any energy savings targets should be set
20 relative to the eligible customer load. In the case of my response to Commission Question
21 1, annual savings of 1.3% of the customer load that *participates* can still be realistically
22 accomplished. While there may be some differences between customer classes in the
23 cost-effective efficiency potential, the targets recommended here fall far short of this

1 theoretical maximum level. Therefore, removing some customers from the program
2 should not affect the ability to reach the target. There are ample opportunities within the
3 remaining customer base.

4 I am more concerned with the potential for *optional* customer exemption from
5 DSM programs. With this policy, the amount of customer load subject to the exception is
6 uncertain, and therefore raises concerns with setting targets before the relevant load
7 subject to program activity is known. Therefore, I concur with SELC Witness
8 Steinhurst's response to Commission Question No. 9 that exempting certain customers
9 from DSM programs is not in the public interest.

10 **Q: Question 6 asks: What is "the range of consumption and peak load reductions that**
11 **are potentially achievable by each generating electric utility?" What is your**
12 **response?**

13 **A:** The savings target as a percentage of forecast loads should be the same for each
14 generating utility as for the state overall. I agree with APCo's contention that each utility
15 should have specific goals expressed as actual MWh and peak MW goals based on each
16 utility's forecast load. However, it is very unlikely that the overall percentage potential is
17 substantially different from utility to utility. There are opportunities in all sectors and
18 customer types, in all geographic regions. If a specific utility has a very unique mix of
19 customers that results in somewhat skewed opportunities, some adjustments may be
20 appropriate based on the potential available from the different customer types. For
21 example, if the residential customer potential percentage is thought to be substantially
22 lower than the industrial percentage, and a particular utility has mostly residential
23 customers and virtually no industrial load, it may be appropriate to make adjustments

1 based on the sectors served. However, except for very small service territories this is
2 generally not an issue.

3 **Q: In response to Question 7, what is your opinion on the range of costs that consumers**
4 **would pay to achieve those reductions, and the range of financial benefits or savings**
5 **that could be realized if the targets were met over a 15-year period?**

6 A: The National Action Plan for Energy Efficiency, as cited in the 2007 Virginia
7 Energy Plan, notes a cost for efficiency savings of between 2 and 3 cents per lifetime
8 kWh. This would imply a range of costs for the suggested targets of between
9 approximately \$3 and \$4.5 billion over the period from 2010 to 2025, or between \$190
10 and \$280 million per year. Based on a conservative benefit-cost ratio of 2.0, this implies
11 total benefits of between \$6 and \$9 billion over the same period.²⁹ These benefits are
12 equal to the avoided spending on traditional energy supply that would be necessary in the
13 absence of the spending on efficiency. Cost-effective energy efficiency investments, by
14 their very definition, will cost Virginia rate-payers less than alternative supply-side
15 resources.

16 **Q: How do you respond to concerns that efficiency programs will raise electric rates for**
17 **Virginia consumers?**

18 A: Consumers pay monthly electric *bills*, not rates. A customer's bill is based on
19 their usage and the rate per kWh (and for some C&I customers, demand charges).
20 *Ultimately, customers want to spend less each month on energy. It is true that cost-*
21 *effective efficiency programs may at time raise rates, primarily because they result in the*

²⁹ The Virginia Energy Plan notes that utility-sponsored efficiency programs save three to four dollars for every dollar spent. Commonwealth of Virginia: Department of Mines, Minerals and Energy. *The Virginia Energy Plan*. 2007. p 60.

1 utility's fixed costs being spread over a smaller number of kWh, making each one more
2 expensive. Customers who choose not to participate in efficiency programs may face
3 slightly higher bills as a result, but these amounts are less than the amount saved by
4 participants. A well designed portfolio of programs will provide opportunities for all
5 customers to participate and strive for high participation rates. By this means, most
6 customers can reduce their energy bill despite small increases in rates.

7 Rate impacts from DSM programs are typically assessed using the Ratepayer
8 Impact Measure (RIM) test. SELC Witness Steinhurst³⁰ and Appalachian Power Witness
9 Castle³¹ agree that this test is not appropriate for policy decisions and evaluating
10 efficiency programs, because it ignores the large benefits to ratepayers as a group from
11 these efforts.

12 **Q: If energy efficiency results in financial benefits for customers, then why should**
13 **efficiency programs intervene in the marketplace?**

14 **A:** Electricity customers face a number of classic market barriers which prevent them
15 from pursuing efficiency measures and investments, even when it would be in their own
16 economic interest to do so. The resulting market failure leaves economically achievable
17 efficiency savings unrealized, resulting in an *over*-commitment to more expensive
18 electric supply. As a consequence, it is necessary to develop programs designed to
19 overcome multiple, interacting market barriers.

20 Some of the more widely-recognized market barriers include:

³⁰ Steinhurst testimony, p. 4.

³¹ Castle testimony, p. 2.

- 1 ▪ Information barriers in the form of customer awareness of energy efficiency
2 opportunities or scarcity of reliable information on the costs and performance of
3 efficiency technologies.
- 4 ▪ Principal-agent barriers, where the person making the efficiency investment does
5 not benefit from the energy savings (e.g., a landlord installing efficient lighting
6 when the tenant reaps the energy bill savings).
- 7 ▪ Financial barriers, including the (usually) larger up-front cost for efficient
8 equipment and transaction costs related to many small investment decisions rather
9 than fewer large ones.
- 10 ▪ Resource barriers, where decision-makers simply do not have the time or
11 expertise to adequately understand the available options for cost-effective energy
12 savings.

13 Contrary to some arguments against efficiency programs, utilities or other
14 efficiency program administrators have the ability to influence customer purchasing
15 decisions, just as in any industry. In general, success comes from treating efficiency as a
16 product or service to be sold like any other. The customer must be aware of it, its benefits
17 must be understood, it must be readily accessible to customers, and it must be priced
18 competitively with the alternatives. It is not sufficient to only address one or two of these
19 factors. As an example, simply providing customers with generic information on
20 efficiency opportunities will generally fail to generate measurable efficiency savings.
21 There are numerous strategies that recognize these needs and overcome the barriers listed
22 above. One of the more effective program interventions involves the direct installation of
23 efficiency measures by the program administrator or their contractor. This approach

1 offers customers a simple turn-key service, often in the small business sector, that
2 identifies opportunities, installs appropriate measures and provides customers with a clear
3 path to attain higher savings. The program administrator typically covers a high
4 percentage of the total installed cost, ranging from 50 to 80 %. This approach addresses
5 all of the barriers listed above. As a result, experience in numerous jurisdictions has
6 shown typical penetration rates from direct install programs targeted at Small C&I
7 customers (those with average peak demand of 200 kW or less) to be between 70 and
8 80%.³²

9 **Q: Please summarize your testimony.**

10 A: In response to Commission Questions 1 and 6, I conclude that efficiency savings
11 of 1.3% of electric load per year can be realistically accomplished in Virginia within a
12 few years. Total efficiency savings through 2022 of greater than 12% of forecast load in
13 that year are also realistic. Peak demand savings in excess of 3,900 MW would be
14 realized in that timeframe, with demand response capable of providing another 1,700
15 MW. These estimates represent levels that can be realistically accomplished; they are far
16 below the cost-effective savings levels that have been estimated to exist in Virginia and
17 other states and do not represent overly aggressive goals. To acquire these savings,
18 Virginia would spend between \$3 and \$4.5 billion, but in doing so would avoid spending
19 twice as much on traditional energy supply.

20 **Q: Does this conclude your testimony?**

21 A: Yes.

³² Mosenthal, P., and M. Wickenden. "The Link Between Program Participation and Financial Incentives in the Small Commercial Retrofit Market," *Proceedings of the 1999 International Energy Program Evaluation Conference*. Denver, CO. August 18-20, 1999. Exhibit SELC-JML-2.



Integrated Energy Resources

**JEFFREY M. LOITER
SENIOR CONSULTANT**

Mr. Loiter has over 12 years of consulting experience in energy and natural resource issues. His energy experience includes policy, planning and program design, research on renewable and efficiency technologies, electricity transmission systems, integrated resource planning and savings verification.

Professional Experience

Optimal Energy, Incorporated

Bristol, VT

Senior Consultant, 2006-present

- Managed the preparation of a DSM plan and Commission filings for Orange and Rockland Utilities. The project included on-site customer audits and residential surveys, efficiency program designs, and an efficiency potential study.
- Supporting the Maryland Energy Administration in their review of utility energy efficiency plans and the design and implementation of state-delivery efficiency programs.
- Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.
- Conducted potential analysis for a Canadian Atlantic province, including commercial and institutional sector program design and overall analytical oversight.
- Developed residential potential analysis for the non-transmission alternative to a proposed transmission line upgrade in Vermont.
- Prepared report on efficiency potential in Texas in support of discussions related to proposed expansion of coal-fired generating capacity, for two major NGOs.
- Prepared a report summarizing the results of extensive potential analysis for a major utility efficiency program expansion in New York State.

Independent Consultant

Cambridge, MA

2005-2006

- Supported the Massachusetts Renewable Energy Trust SEED Initiative by evaluating renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards pending approval total \$1.4 million.
- Led an effort to draft a whitepaper on policies to encourage investment in electricity transmission facilities.

- Completed two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in *Petroleum Technology Quarterly* (1Q 2006) and *BCC Research/Energy Magazine* (2006).

Industrial Economics, Incorporated

Cambridge, MA

Associate, 1997-2000; Senior Associate, 2001-2004

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Incorporated

New Orleans, LA & Boston, MA

1991-1995

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

Education

M.S., Technology & Policy, Massachusetts Institute of Technology, Cambridge, MA, 1997.

B.S. with distinction, Civil and Environmental Engineering, Cornell University, Ithaca, NY, 1991.

Publications

"From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers," (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings*, Pacific Grove, CA, August 2008.

Exhibit SELC-JML-2

Testimony of Jeffrey Loiter

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**1999 INTERNATIONAL
ENERGY PROGRAM
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**The Ninth International
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The Link Between Program Participation and Financial Incentives in the Small Commercial Retrofit Market

*Philip H. Mosenthal, Optimal Energy, Inc., Bristol, VT
Michael Wickenden, Citizens Utilities Company, Newport, VT*

ABSTRACT

The stakes involved in accurately predicting customer response to different energy efficiency strategies are high. Many utilities and energy service companies have tried to minimize the costs of program delivery, while still capturing maximum savings, with varying success. In many cases, program participation and savings levels have dropped dramatically, resulting in substantial lost net benefits and savings opportunities. On the other hand, increasing program costs in ways that do not substantially impact savings levels may result in unnecessarily high utility and ratepayer costs.

The prediction of customer participation and energy efficiency measure adoption in program planning is particularly difficult because there is no single variable that clearly dominates all others in energy-user decision-making. Nonetheless, studies have generally found a positive correlation between the level of financial incentive provided to customers and the level of participation. Unfortunately, many of these studies have not controlled for numerous other variables that impact participation, such as different markets, marketing approaches, delivery mechanisms and implementation procedures.

This paper analyzes the relationship between program participation and the level of financial incentives offered in the small commercial retrofit market. Unlike other studies, it relies on a rich database of program activity for a single program in which virtually all other program design and implementation procedures were held constant. It confirms many previous research results, yet provides some indication that other non-cash rebate strategies may be more effective in this market than previously thought.

Introduction

A fundamental question in designing energy efficiency programs is the prediction of customer participation and measure adoption, given different program design strategies. A number of studies have analyzed how participation is related to financial and other program strategies. However, it is often difficult to apply these research findings to other programs or markets. Many studies analyze a cross section of data from diverse programs operating by different utilities, in different markets, and sometimes with different data definitions (e.g., Berry 1990; MECO 1993; Nadel 1996; Nadel, Pye & Jordan 1994; Pratt 1993). Others analyze time series data for a single program that may undergo a multitude of changes over the analysis period (e.g., Holt 1992). These research results must be applied with caution because customer participation is impacted significantly by many non-financial factors as well, including marketing, technical assistance, ease of participation and utility-customer relations (Berry 1990).

To inform future program design, Citizens Utilities Company (CUC) analyzed the relationship between customer participation and the level of incentives observed in its Small Commercial and Industrial Retrofit Program (SCIP), delivered from 1993 to 1995. Unlike other studies, this investigation relied on data from a single program, over a period when the program design and delivery were virtually constant. Because the program incentive structure offered each customer a

customized financial package, the analysis compares the responses to different financial offers, holding most other important factors constant.

As expected, customer participation and measure adoption rates generally declined with falling financial contributions by the utility (as a percent of total project cost). However, we also found participation did not decline as quickly or substantially as expected.

Analytical Approach

Program Description and Data

Two hundred and thirty-six small commercial and industrial (C&I) customers participated in the SCIP. The program provided direct audit and energy efficient equipment installation services, and financial strategies to encourage customer participation. The program primarily addressed lighting, although motors, refrigeration, water heating, and space and water heating fuel switching measures were also recommended.

The financial incentives for all measures except fuel switching included a mix of cash rebates and zero interest financing, tailored to each customer. The financing was designed to provide an immediate positive cash flow to the customer and be paid back on the electric bill. No incentives were provided for fuel switching measures. As a result, the portion of project cost covered by CUC varied from 0% to 100%, depending on the type of measures, the magnitude of the project, and the estimated customer bill savings. Overall, 74% of customers receiving audits installed at least some measures. Approximately 50% of the identified and recommended measures were implemented. When excluding fuel switching, the overall adoption rate of recommended measures was about 65%.

The SCIP offered customers the following financial incentive structure for non-fuel switching measures:

- CUC pays 100% of the first \$750 of project cost.
- CUC provides 0% interest financing on the balance of the project cost.
- Customer pays back the financed portion with payments set to a maximum of 50% of estimated bill savings (percentage increases as project cost increases).
- Customer makes payments for a term of either 5 years, or until 100% of the financing balance is paid back, whichever occurs first.

The above incentive structure results in customers with very low cost projects (i.e., less than \$750) paying nothing. In general, the higher the project costs or payback periods, the lower the incentive level. Because of the relationship between project cost, bill savings, and incentive level, these other factors were examined as well to try to isolate the financial incentive effect.

The participant database contained information for each customer that received an audit, including the recommended and actual installed project cost and estimated savings, and the types of measures recommended and installed.

Because of the clear distinction between fuel switching and non-fuel switching measures (in terms of incentives, technologies and market barriers), fuel switching and non-fuel switching projects were analyzed separately. Of the 236 customers, 12 were omitted from the analysis because of poor data.

Analysis

Participation Parameters. The analysis investigated the relationship of three different participation parameters to overall incentive levels:

1. the mean customer measure adoption rate (customer installation \$/customer recommended \$);
2. the overall measure adoption rate (total installation \$/total recommended \$); and
3. the proportion of audit customers installing any measures.

The first parameter provides an indication of the estimated portion of recommended savings that a customer is likely to install given a particular incentive offer. The second parameter places greater weight on bigger projects, and provides an indication of the overall portion of savings from a customer population likely to be acquired with a given incentive offer. Finally, the third parameter provides an estimation of the proportion of customers that would be willing to install any measures at all. While all three parameters are highly correlated, analysis of the differences between them provides some insight into other issues, including variations in comprehensiveness and project size.

Incentives. Incentive level is defined in terms of the portion of total recommended project installation cost that CUC offered to pay.

Each customer was presented with a written financial offer that showed the customer's estimated positive cash flow, and the allocation of overall project costs between the customer and CUC, ignoring the time value of money. As a result, it is not clear whether customers based their decisions solely on this "undiscounted" incentive level shown, or whether they also inherently considered the additional value of the financing interest buy-down provided by CUC. Warner (1994) found that most small commercial customers tend to *over value* the savings from 0% interest financing when choosing between alternate financing packages. However, the Warner customer sample may not have been provided with information similar to that given the CUC customers. Consequently, we examined the relationship of participation to both undiscounted and discounted incentive levels.¹ For purposes of utility planning, the discounted incentive level figures may be more useful because they more closely reflect the true costs to the utility. We also analyzed the participation response to fuel switching recommendations (0% incentive) to provide an indication of likely response from information-only efforts.²

Partial Versus Complete Measure Adoption. A review of the data, and interviews with the program implementation contractor, indicated that most, but not all, customers tended to accept or decline the recommended package *in toto*, rather than adopting only a portion of measure recommendations. As a result, the distribution of the ratio of installed to recommended costs for those accepting measures tended to be clumped around 100%. However, because *a priori* cost estimates are imperfect, and change orders may occur during installation, the ratio was often slightly more or less than 100%.

Because our focus is on customer response to the initial offer (as opposed to the accuracy of installation cost estimation), and the theoretical implausibility of capturing greater than 100%

¹ While the present value cost to the utility of incentive levels would be discounted based on its weighted cost of capital, we calculated the value of the interest buy-down based on a more typical interest rate (12%) available to small commercial customers to more closely reflect the customer decision-making process.

² Comparisons between the fuel switching and non-fuel switching responses must be made with caution given the lack of positive cash flow financing, and the somewhat different barriers faced with these decisions.

participation, all individual customer proportions of installed to recommended project cost greater than 75% were set to 100%.³ Because most of the projects set to 100% had actual ratios above 100%, this adjustment has the effect of slightly reducing overall estimated participation proportions.

Stratification. The individual participation data was grouped into strata reflecting incentive level ranges. Table 1 shows definitions, sample sizes, and average overall parameter proportions for each strata. Figure 1 shows graphically how the parameters vary by incentive level strata. We investigated the likelihood that the sample parameter proportions for each stratum are statistically different. T-statistics and confidence levels that the strata mean proportions are different are reported in Table 2.

Table 1. Participation and Installation Rates, by Discounted Incentive Level Strata

| Strata | Strata range (recommended incentive) | Sample Size (n) | Mean Customer Installation Rate (Installed\$/recommended\$) | Overall installation rate by strata (total installed\$/total recommended\$) | Percent of participants who installed anything |
|--------|--------------------------------------|-----------------|---|---|--|
| 1 | 90-100% | 58 | 84% | 91% | 84% |
| 2 | 70-89% | 60 | 74% | 66% | 75% |
| 3 | 50-69% | 64 | 61% | 54% | 63% |
| 4 | 20-49% | 44 | 77% | 65% | 80% |
| 5 | 0% | 53 | 6% | 4% | 8% |
| 1&2 | 70-100% | 116 | 79% | 72% | 79% |
| 3&4 | 20-69% | 108 | 68% | 59% | 69% |

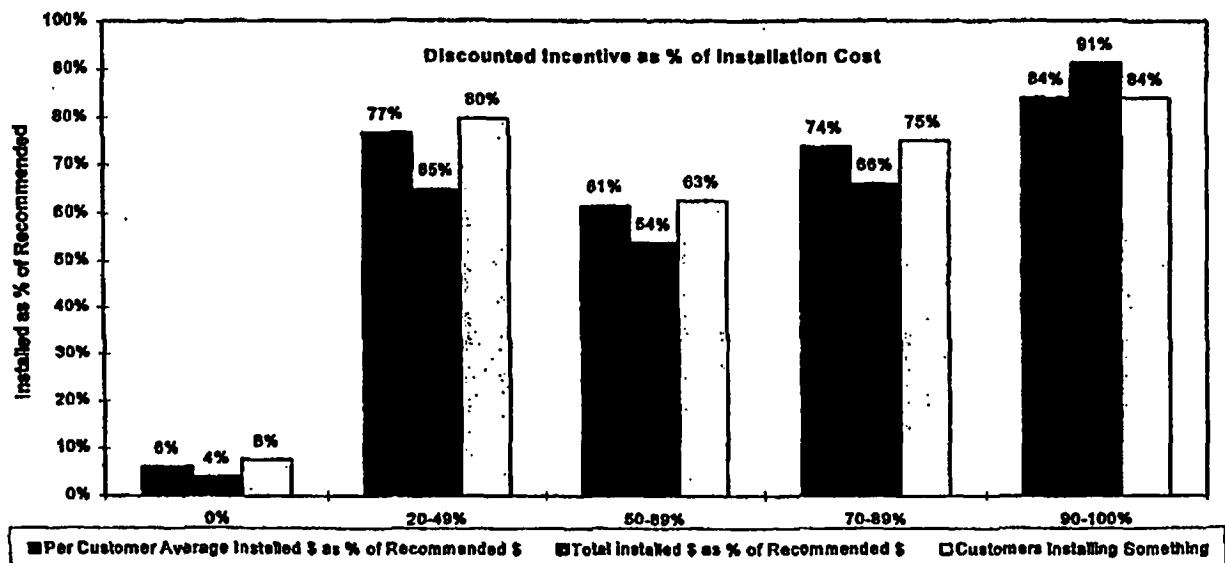


Figure 1. Customer Response to % of Installation Cost Offered

³ The 75% cut-off was selected from a review of the data, and judgment about which specific projects seemed to be complete, rather than partial based on the kWh saved.

Table 2. Confidence Levels that Strata Mean Proportions are Different

| Strata Comparisons | Mean Customer Installation Rate (installed\$/recommended\$) | | Overall installation rate by strata (total installed\$/total recommended\$) | | Percent of participants who installed anything | |
|--------------------|---|------------------|---|------------------|--|------------------|
| | t-Statistic | Confidence Level | t-Statistic | Confidence Level | t-Statistic | Confidence Level |
| 1 to 2 | 1.37 | 82.6% | 3.50 | 99.9% | 1.20 | 76.7% |
| 2 to 3 | 1.46 | 85.4% | 1.41 | 84.0% | 1.52 | 86.8% |
| 3 to 4 | 1.71 | 91.0% | 1.17 | 75.6% | 1.99 | 95.0% |
| 4 to 5 | 9.83 | 100.0% | 7.92 | 100.0% | 10.17 | 100.0% |
| 1 to 3 | 2.87 | 99.5% | 5.14 | 100.0% | 2.75 | 99.3% |
| 1 to 4 | 0.91 | 63.8% | 3.24 | 99.8% | 0.56 | 42.4% |
| 1+2 to 3+4 | 1.86 | 93.6% | 2.05 | 95.8% | 1.70 | 90.9% |

Logit Analysis. While the analysis by strata shows clear differences between likely participation over distinct incentive level ranges, it is difficult to interpolate results, or estimate an overall predictive relationship. Some studies (Camera, Stormont & Sabo 1989) have performed regression analyses on participation data to estimate the typical relationship over the range of possible incentive values. However, because participation is bounded (on the low end at 0%, and on the high end at 100%), a simple regression will tend to oversimplify the relationship, and fail to capture the variations in slope over the full range of incentive levels. Clearly, as participation approaches 100%, a given percent increase in incentive must result in a smaller and smaller % increase in participation.

We performed a logit probability analysis on the bounded data (Figure 2), using the following functional form:

$$\log[P/(1-P)] = \alpha + \beta X + \epsilon$$

where: P = the proportion of per-customer overall recommended measure \$ actually installed
 X = the incentive level as a percent of total project cost

Ideally, the logit analysis would be done by simply regressing $\log[P/(1-P)]$ on X. However, because many observations of P are either 0 or 1.0, the regression fails. To solve this problem, we performed the logit analysis on the five discounted incentive level strata. Ideally, maximum likelihood estimation (MLE) should be performed to avoid the introduction of possible bias, and is an area for future research.

Results

Differences in Proportions

Figure 1 shows a steady decline in all participation parameters as incentive levels decrease from 100% to 50% (strata 1, 2 & 3). Participation parameters then *increase* for stratum 4 (20-49% incentive), before dropping off precipitously in the last stratum (0%, fuel switching). The differences

between any two adjoining strata participation rates are significant at the 75% confidence level or higher.

Looking at the overall installation rate parameter, the drop from 91% to 66% between strata 1 & 2 is highly significant at 99% confidence. The next drop from 66% to 54% (strata 2 to 3) is less significant at 84% confidence level. The unexpected increase in participation in stratum 4 is only significant at the 76% confidence level, indicating that this increase may be an anomaly. All comparisons to the 0% incentive (fuel switching) stratum are highly significant, at 99.99% confidence.

When combining strata 1&2 (70 – 100%) and strata 3&4 (20 – 69%), the difference in all parameters is significant at 90% confidence or higher, with the overall installation rate significant with 96% confidence.

These results seem to suggest a significant and large reduction in participation can be expected when dropping from relatively high incentives (90 to 100%) to incentives covering somewhere around half to two thirds of the installation cost. Continued reductions in incentives in the mid-level range seem much lower, or possibly even insensitive to incentive level. This is supported by other research on the subject. For example, Holt (1992, p. 13) notes "high incentives appear to promote greater participation than moderate incentives, but the impact of low and moderate incentives may be indistinguishable." This general trend was also identified by Warner (1994).

The variation between different participation parameters seems to indicate that the overall level of savings and measure comprehensiveness may drop off more dramatically with reductions in incentives than the decision to participate at all does. It is possible that, given the SCIP incentive structure, low incentive levels may still encourage customers to do some measures, while foregoing other cost-effective measures. While the significance of these shifts in parameters was not tested, similar results have been found in cross-sectional comparisons of other C&I programs (Holt 1992; Nadel, Pye & Jordan, 1994). Further research might determine whether this observation holds for larger or more diverse samples, or under different incentive designs.

When considering undiscounted incentive levels, the results follow a similar pattern. Surprisingly, participation levels remained in the 60% range even with very low incentives. This is consistent with theories that simply having an incentive may be more important than the magnitude of it (Vine & Harris 1988), and that financing services are most valued by customers when the utility incentive is lowest (Warner 1994).

Because of the incentive structure, a high proportion of large projects, and those where the bill savings were highest, tend to be at the low incentive levels. We therefore examined the effect of increased project cost on participation, and whether increased net bill savings caused a higher likelihood of participation. Our hypothesis was that the surprisingly high levels of participation at relatively low incentive levels might be a result of larger customers, and those with the greatest potential bill reductions, being more likely to participate. However, in both these cases, participation went *down* as either project cost or net bill savings increased. This trend is counter to many energy efficiency programs, where larger customers tend to have a greater likelihood to participate than smaller ones (Warner 1994).⁴

Logit Analysis

The logistic curve in Figure 2 shows the estimated relationship of the overall measure installation rate to discounted incentive levels. This curve predicts participation of approximately 91% at 100%

⁴ While project cost and customer size are not linked, they tend to be highly correlated, particularly for direct install programs, such as this one, with a high concentration of lighting measures.

incentive, dropping down to about 80% at an 80% incentive level. These results are almost identical to those achieved by Massachusetts Electric Company's similar Small Commercial Retrofit Program (Nadel & Geller 1995, pp. 17-18), perhaps indicating that in the small commercial market, results of similar programs are relatively transferable from one utility to another, at least within the same general geographic region.

At the low end of the curve, the y-intercept of 6.5% predicts the participation rate for a program offering information-only.

Because no positive-cash-flow financing was offered for fuel switching we also estimated a logistic curve omitting the fuel switching data. Under this scenario, participation with no incentive (other than positive-cash-flow financing) is significantly higher (25.7%), but then increases less rapidly over the range of incentive levels. This curve may better predict future program participation when positive-cash-flow, on-the-bill financing is offered without rebates or an interest buydown.

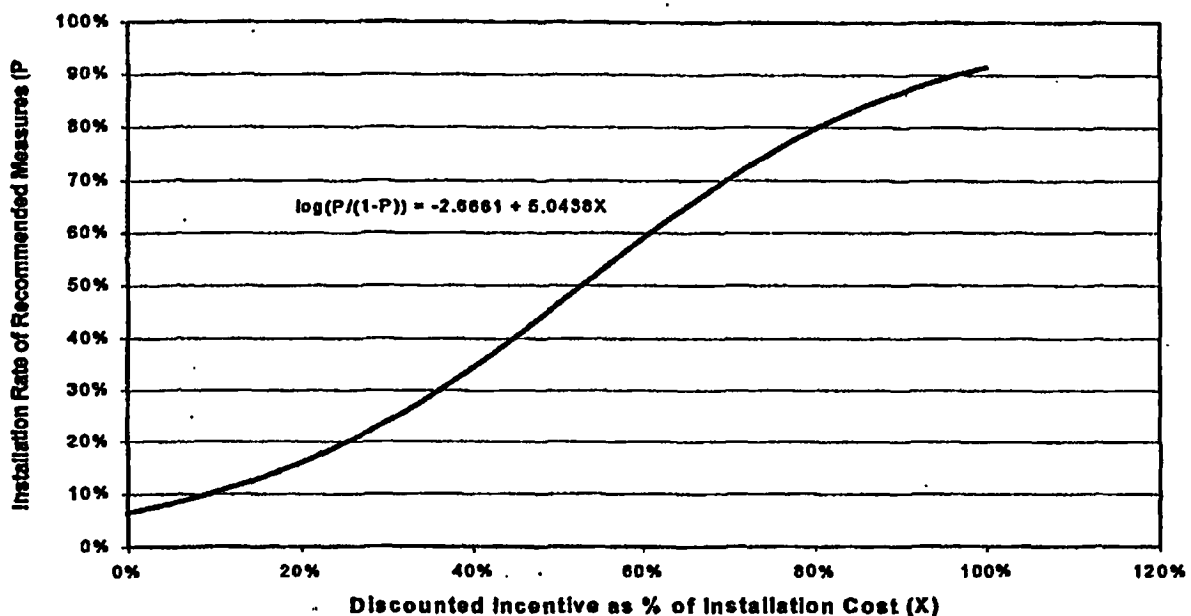


Figure 2. Logistic Curve

Inferences and Implications for Program Design

The general trend of dropping participation levels with dropping incentives both confirms expectations and is consistent with most other findings (e.g., Berry 1990; Holt 1992; Nadel 1996; Nadel and Geller 1995; Nadel, Pye and Jordan 1994; Warner 1994). However, most estimates predict much higher drop-offs in participation at mid to low incentive levels than were achieved by CUC. For example, Warner (1994) estimates 30% participation at 50% incentive levels for small commercial retrofit programs — less than half of CUC's achieved rate. The CUC data shows participation decreasing significantly as incentives drop from very high to medium, but then leveling off and becoming relatively insensitive to incentive level as incentives drop below approximately 50%.

It is possible that CUC's ability to provide customers immediate positive cash flow may be as significant to many customers as the overall incentive levels. This theory might explain the clear and

precipitous drop when positive-cash-flow financing was no longer offered (for the fuel switching measures), and the maintenance of relatively high participation levels even at quite low incentive levels when the financing was available. For example, at discounted incentive levels of only 20% to 49%, the overall participation rate is estimated at 65%, but then drops to only 4% when customers are offered a 0% incentive. If these results are replicable at low incentive levels, they would represent a divergence from other analyses that have found little success in small commercial markets with significant customer cost contributions (MECO 1993). Because of the clear distinctions between the fuel switching and non-fuel switching measures and incentive structures, this hypothesis is difficult to test. An area for further research may be testing the relative influences of positive-cash-flow financing on small commercial customer decision-making.

The data may indicate that financing has the potential to substantially increase participation rates for those programs offering low incentives, at much lower cost to utilities. A few financing programs have had some success (e.g., Pacificorp's Energy FinAnswer Program).⁵ However, most recent research indicates that in most cases, financing or shared savings approaches have failed to effectively substitute for cash rebates in achieving substantial participation, particularly in the small commercial market (Prindle 1995; MECO 1993; Nadel 1996). It is possible that CUC succeeded in capturing high levels of participation through careful design of its financing services. Key design parameters include:

- **Provision of immediate and significant positive cash flow.** All customers not only received immediate positive cash flow, they also retained at least 50% of their estimated bill savings, in some cases significantly more.
- **Simple qualifying mechanisms.** It is critical to simplify the credit application process. Customers who have kept current with their electric bill payments will presumably be able to make the loan payments because their total costs will go down. In addition, by combining payments on the bill, utilities may be able to increase their leverage over non-payers. Utilities should eliminate traditional credit approvals and streamline the process. This is particularly important for tenants.
- **Simple repayment mechanisms.** All repayments were included in the regular monthly electric bills. Not only does this minimize transaction costs and the inconvenience of another loan, it reinforces the impact of the immediate positive cash.

Figure 3 shows the predicted present value net benefits of a small C&I retrofit program, under different assumptions about incentive levels, based on the estimated logistic curve. The net benefit analysis is based on actual administrative, audit, and installation program costs for CUC, and current Vermont statewide electric avoided cost estimates (VT DPS, 1997). Its applicability to much larger utilities that could potentially lower per-customer administrative costs is somewhat limited.

⁵ While Pacificorp's program achieved a 76% participation in its Oregon territory (Prindle 1995, p. 68), a 35% cash incentive (in the form of tax credits) from the state was available at the time to supplement the utility financing. Pacificorp's participation level in other areas was substantially lower (Nadel 1996, p. 30).

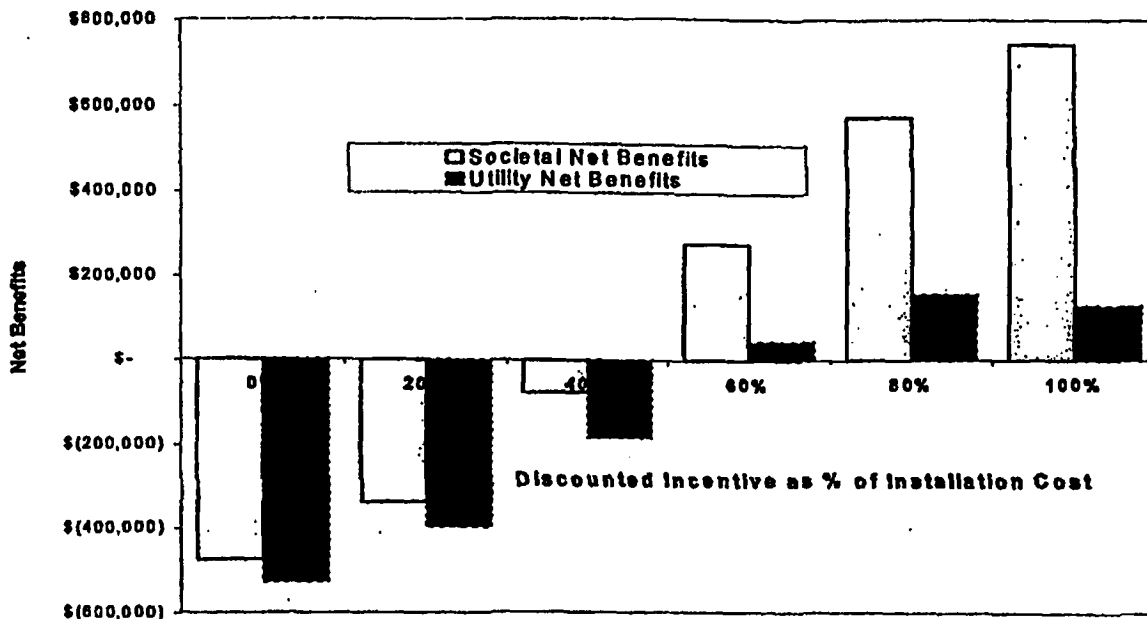


Figure 3. Program Cost-Effectiveness vs. Incentive Level Offered

Obviously, societal net benefits are maximized under a 100% incentive approach.⁶ When comparing *utility* net benefits (total utility program costs less avoided electric cost benefits), it appears that the optimal strategy is not that different than under a *societal* analysis. The point of maximum utility net benefit is when the utility pays approximately 80% of the installation cost.

This confirms predictions by some others that requiring substantial customer cost contributions may actually *increase* net utility costs, as well as lower overall savings (e.g., Berry 1990; Gettings & MacDonald 1989; MECO 1993; Nadel, Pye & Jordan 1994; NEPSCO 1992; Pratt 1993). Our analysis indicates that, for a small utility, the lower incentive payments would be more than offset by the increased marketing, audit and administrative costs required to capture the same level of gross avoided cost benefits.

Conclusions

Our overall analysis confirms much of the prior research. It shows statistically significant reductions in participation parameters and measure adoption rates as financial incentives go down. In addition; it seems to confirm other hypotheses that participation levels are more sensitive to incentive changes at high levels of incentives (80-100% of project cost), than across the mid-range of incentives (30-70% of project cost).

The analysis diverges somewhat from prior findings that at low levels of incentives (10-40% of project cost) participation will drop off significantly. It is possible that the relatively high levels maintained by CUC are, at least in part, a result of the offer of immediate positive-cash-flow, on-the-bill, easy-to-use financing. It may be that properly designed financing services are a more important incentive to customers when the total utility contribution is lowest, and are least significant at very high levels of utility contribution. The CUC program results seem to diverge significantly from most of

⁶ Customer incentives are transfer payments from non-participating ratepayers to participants, and therefore have no impact on societal costs.

the recent research that has found very few examples of successful financing services in utility programs (in terms of achieving significant levels of participation and savings).

While CUC was able to maintain relatively high participation levels at the relatively low incentive levels, the data seems to indicate a loss of comprehensiveness and overall savings that is greater than the loss in participation rate. This confirms other cross-sectional research of C&I programs.

The logit analysis seems to indicate that the overall net benefits to utility ratepayers are maximized with incentives in the high range of 80% to 100% of project cost. Again, this is consistent with some prior research.

Finally, our analysis identifies areas for further research. The CUC analysis benefited from a rich database, and the control of many non-financial variables. However, it raises questions about the impact of positive-cash-flow financing, both combined with and without cash rebates. Future tests that isolate different financial strategies may shed light on these effects. Other fruitful areas of research include testing the significance of changes between levels of measure comprehensiveness and overall participation levels, and improving on the logit model by employing MLE techniques.

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COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
AT RICHMOND, OCTOBER 5, 2012

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COMMONWEALTH OF VIRGINIA, *ex rel.*

STATE CORPORATION COMMISSION

CASE NO. PUE-2011-00092

In re: Virginia Electric and Power Company's
Integrated Resource Plan filing pursuant
to Va. Code § 56-597 *et seq.*

FINAL ORDER

On September 1, 2011, Virginia Electric and Power Company d/b/a Dominion Virginia Power ("Dominion" or "Company") filed its Integrated Resource Plan ("IRP") with the State Corporation Commission ("Commission") as required by § 56-599 C of the Code of Virginia ("Code"). Pursuant to § 56-599 E of the Code, the Commission must, after giving notice and an opportunity to be heard, determine whether Dominion's IRP is reasonable and is in the public interest.

On September 26, 2011, the Commission issued an Order for Notice and Comment in this proceeding that, among other things, directed Dominion to provide public notice of its IRP and afforded interested persons an opportunity to file comments or request a hearing on the Company's IRP. The Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of the Sierra Club (collectively, "Environmental Respondents"), the Virginia Committee for Fair Utility Rates ("VCFUR"), MeadWestvaco Corporation ("MeadWestvaco"), Doswell Limited Partnership ("Doswell"), the Electric Power Supply Association ("EPSA"), and the Office of the Attorney General—Division of Consumer Counsel ("Consumer Counsel") filed notices of participation in this proceeding. Numerous comments related to the Company's IRP also were received, including comments from Consumer Counsel, EPSA, and the Environmental Respondents. The Environmental Respondents also requested a hearing.

On January 6, 2012, the Commission issued its Order Scheduling Hearing ("Order"), granting the Environmental Respondents' request for hearing. The Commission's Order, among other things, also provided for the pre-filing of testimony and exhibits by Dominion, respondents, and the Staff of the State Corporation Commission ("Staff"). The Company, Staff, Environmental Respondents, and EPSA pre-filed testimony in this proceeding.

On May 8, 2012, the Commission convened an evidentiary hearing on the Company's IRP. At the outset of the hearing, the Commission received public testimony. Thereafter, the Company, Staff, Environmental Respondents, EPSA, VCFUR, and Consumer Counsel fully participated at the hearing.¹ At the conclusion of the evidentiary hearing on May 10, 2012, the Commission directed the parties to file post-hearing briefs on the legal issues relevant to this case. On August 8, 2012, the Company, Staff, Environmental Respondents, EPSA, VCFUR, and Consumer Counsel filed post-hearing briefs. On August 16, 2012, Doswell also filed a post-hearing brief in this proceeding.²

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds, subject to the requirements and limitations discussed below, that Dominion's IRP is reasonable and in the public interest for the specific purpose of filing the planning document mandated by §§ 56-597 *et seq.* of the Code.

As we noted in Dominion's prior IRP case, the IRP is a planning document, not a document that will control future decisions on specific resources. Thus, we described the IRP proceeding in the following manner:

¹ MeadWestvaco and Doswell did not appear at the hearing.

² Specifically, on August 16, 2012, Doswell filed its Motion of Doswell Limited Partnership to File Post-Hearing Brief Out-of-Time and Post-Hearing Brief. On August 22, 2012, Dominion filed its Response to Doswell's motion in which the Company asserted that Doswell's proposed Post-Hearing Brief contained certain factual mischaracterizations. Neither Staff, nor any respondent filed responses to Doswell's motion. We grant Doswell's Motion to File Post-Hearing Brief Out-of-Time and accept Doswell's Post-Hearing Brief and Dominion's Response.

As such, the Commission's determination in this proceeding does not preclude the Commission from approving or rejecting a particular supply-side or demand-side resource in the future, nor does the Commission's determination in this case create any presumption in favor, or not in favor, of a particular resource, including generation construction projects, generation from non-utility generators, conservation or other options.³

Accordingly, the reasonableness and prudence of any actual or projected expenditures toward one or more specific demand- or supply-side resource option is not an issue in an IRP proceeding. Indeed, in the instant case, the Commission previously directed as follows:

Dominion acknowledged that actual expenditures incurred toward any specific resource option that has not been approved by this Commission in an applicable formal proceeding are incurred solely at the risk of Dominion's stockholders. Further, . . . finding that an IRP is reasonable and in the public interest under § 56-599 E of the Code in no manner represents – *and should not be characterized as representing* – explicit or implicit approval for construction or cost recovery of any specific resource option contained in the IRP.⁴

With regard to the IRP submitted by Dominion in this proceeding, we find deficiencies in the breadth of some of the Company's modeling used for the IRP. For example, as discussed by Staff and respondents, the planning models forced the addition of North Anna 3 into each plan.⁵ Dominion suggested, in part, that this restriction was designed to address fuel diversity.⁶ Dominion is not precluded from submitting its preferred models in the IRP, and the Commission is aware of arguments regarding diversity of fuel mix. Such considerations, however, do not

³ *Commonwealth of Virginia, ex rel., State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUE-2009-00096, 2010 S.C.C. Ann. Rept. 385, Final Order at 5-6 (Aug. 6, 2010).

⁴ *Commonwealth of Virginia, ex rel., State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUE-2011-00092, Doc. Con. Cen. No. 120320147, Order on Certified Question at 4 (Mar. 19, 2012) (emphasis added).

⁵ *See, e.g.*, Staff's August 8, 2012 Post-Hearing Brief at 2-6; Consumer Counsel's August 8, 2012 Post-Hearing Brief at 5-6; VCFUR's August 8, 2012 Post-Hearing Brief at 12-14.

⁶ *See, e.g.*, Tr. 191, 304-305; *see also* Dominion's August 8, 2012 Post-Hearing Brief at 12-15.

warrant limiting the IRP as presented by Dominion. Thus, Dominion's future IRP filings also shall include models where North Anna 3 (if included in subsequent IRPs) competes against other resource options.⁷

Dominion also excluded new coal-based alternatives, because, "[a]ccording to the Company, it decided not to move forward with coal-fired technologies at this time due to uncertainties surrounding future carbon dioxide legislation."⁸ As further noted by Staff, "non-carbon capture sequestration capable coal technologies were not considered for analysis in the Company's busbar screening model."⁹ Again, while Dominion may submit its preferred models, we find that future IRP filings should not be so limited. A decision to prohibit the construction of any type of power plant, coal-fired or otherwise, in Virginia is a policy decision for the General Assembly. Accordingly, Dominion's future IRP filings shall include consideration of non-carbon capture sequestration capable coal resources (as new construction and through the purchase of existing facilities) relative to other technologies included in its busbar screening process. In sum, both coal and nuclear options should be considered against the full panoply of conventional, renewable, and other resource alternatives.

We also believe that Dominion should adequately consider third-party market alternatives as capacity resources. We do not conclude, however, that Dominion should be required to perform independent market tests as part of the IRP because, as noted by Consumer Counsel, "the IRP is a planning document, and is not a commitment to pursue any particular

⁷ See, e.g., Staff's August 8, 2012 Post-Hearing Brief at 10.

⁸ Ex. 22 (Stevens) at 11; see also Ex. 2 (IRP) at 69.

⁹ Ex. 22 (Stevens) at 13.

investment."¹⁰ Rather, we find that market alternatives are appropriate for consideration in cases where Dominion seeks a certificate of public convenience and necessity for specific investments. Indeed, the Commission has previously explained that third-party alternatives, including purchased power and new construction, "would likely be relevant evidence in an application proceeding [for a self-build option for new generation]."¹¹

The Environmental Respondents request "the addition of generic blocks of DSM in the middle and later years of the planning period."¹² The Company notes that its IRP "sets forth the 2010 Commission-approved DSM programs, the proposed DSM programs that were pending approval through the most recent DSM proceeding, and currently identified future DSM programs for which approval may be sought from this Commission at a later time," and that generic DSM blocks "would have little meaning [and] be potentially misleading."¹³ We find that the IRP should continue to model DSM alternatives but will not require changes thereto. Further, we note that Staff submitted a specific exhibit directly comparing the costs of demand- and supply-side alternatives.¹⁴ Any future application for approval of a specific DSM resource obviously must be found reasonable under the particular statutory requirements relevant to such request.

¹⁰ Consumer Counsel's August 8, 2012 Post-Hearing Brief at 5.

¹¹ *Application of Virginia Electric and Power Company, For a certificate to construct and operate a generating facility; for certificates of public convenience and necessity for a transmission line: Bear Garden Generating Station and Bear Garden-Bremo 230 kV Transmission Interconnection Line*, Case No. PUE-2008-00014, 2009 S.C.C. Ann. Rept. 296, Final Order (Mar. 27, 2009).

¹² Environmental Respondents' August 8, 2012 Post-Hearing Brief at 4.

¹³ Dominion's August 8, 2012 Post-Hearing Brief at 19-20.

¹⁴ Ex. 23 ES (Walker).

Next, we conclude that rate design issues are appropriate for consideration in IRP as well as other proceedings. As discussed by Staff: "[R]eviewing rate design in an IRP would not be intended to re-establish the design of a Company's rates. Instead, the purpose of such review would be to identify: (i) potential, generalized designs; and (ii) possible rate design pilot programs."¹⁵ In addition, Consumer Counsel discusses rate design options that may affect energy usage over the longer term.¹⁶ In future IRPs, rate design options should be modeled by the Company, for example, to analyze how alternative rate designs may impact demand and the plans to meet demand, particularly given Dominion's "commitment to meeting the Commonwealth's [10%] energy reduction goals."¹⁷

Finally, we conclude that no changes shall be required to the stakeholder process and reports previously undertaken by Dominion between its biennial IRP filings.

Accordingly, IT IS SO ORDERED AND this matter is dismissed.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219.

¹⁵ Staff's August 8, 2012 Post-Hearing Brief at 8.

¹⁶ See, e.g., Consumer Counsel's August 8, 2012 Post-Hearing Brief at 6-7.

¹⁷ Ex. 24 (Wood Rebuttal) at 5.

SOUTHERN ENVIRONMENTAL LAW CENTER

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March 15, 2012

VIA ELECTRONIC FILING

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

**RE: Virginia Electric and Power Company's Integrated Resource Plan filing
pursuant to VA Code § 56-597 et seq.**

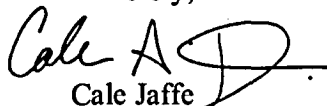
Case No. PUE-2011-00092

Dear Mr. Peck:

Enclosed for filing in the above-captioned matter is the Direct Testimony of Jeffrey Loiter on behalf of Environmental Respondents.

This filing is being completed electronically, pursuant to the Commission's Electronic Document Filing system. If you should have any questions regarding this filing, please call me at (434) 977-4090.

Sincerely,



Cale Jaffe
Southern Environmental Law Center

cc: Parties on Service List
Commission Staff

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00092
March 15, 2012*

**TESTIMONY
OF
JEFFREY LOITER**

**ON BEHALF OF
THE CHESAPEAKE CLIMATE ACTION NETWORK, APPALACHIAN
VOICES, AND THE VIRGINIA CHAPTER OF THE SIERRA CLUB**

**Virginia State Corporation Commission
Case No. PUE-2011-00092**

MARCH 15, 2012

*Direct Testimony of Jeffery Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00092
March 15, 2012*

1 **Q. Please state your name and business address.**

2 A. My name is Jeffrey Loiter and my business address is Optimal Energy, Incorporated, 14
3 School Street, Bristol, VT 05443.

4 **Q. On whose behalf are you testifying?**

5 A. I am testifying on behalf of the Chesapeake Climate Action Network, Appalachian
6 Voices, and the Virginia Chapter of the Sierra Club (collectively, “Environmental
7 Respondents”).

8 **Q. Mr. Loiter, by whom are you employed and in what capacity?**

9 A. I am employed as a Managing Consultant by Optimal Energy, Inc., a consultancy
10 specializing in energy efficiency and utility planning. In this capacity, I direct and
11 perform analyses, author reports and presentations, manage staff, and interact with clients
12 to serve their consulting needs. My clients include utilities, NGOs, state energy offices
13 and efficiency councils, and third-party program administrators. For example, I provide
14 Orange & Rockland Utilities with consulting services on program design and
15 implementation and participate on the consultant team supporting the work of the
16 Massachusetts Energy Efficiency Advisory Council.

17 **Q. Please summarize your work experience and educational background.**

18 A. I have 15 years of experience in environmental and economic consulting. For the past 5
19 years, I have been engaged in a variety of work at Optimal Energy related to energy
20 efficiency program design and analysis. For example, I prepared two documents for
21 inclusion with EPA’s *National Action Plan for Energy Efficiency (NAPEE)*: a guidebook

1 on conducting efficiency potential studies, and a handbook describing the funding and
2 administration of clean energy funds.¹

3 In my capacity as a Managing Consultant at Optimal, I also advise clients on
4 efficiency program design and implementation. For example, I recently contributed to a
5 5-year Energy Efficiency and Demand Response Plan for the Tennessee Valley
6 Authority. I have also participated in several studies of efficiency potential and
7 economics, including ones in New York, Vermont, Texas, Massachusetts, and Prince
8 Edward Island. These studies have ranged from macro-level assessments to extremely
9 detailed, bottom-up assessments evaluating thousands of energy efficiency measures
10 among numerous market segments.

11 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
12 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
13 Environmental Engineering from Cornell University and an *M.S.* in Technology and
14 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
15 ER-JML-1.

16 **Q. Have you previously testified before the Virginia State Corporation Commission**
17 **(“the Commission” or “SCC”)?**

18 **A. Yes, I testified on behalf of the Southern Environmental Law Center, Virginia Chapter of**
19 **the Sierra Club and Appalachian Voices in Case No. PUE-2009-00023. More recently, I**
20 **testified on behalf of Environmental Respondents in Case No. PUE-2011-00093,**

¹ These documents can be found at http://www.epa.gov/cleanenergy/documents/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

*Direct Testimony of Jeffery Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00092
March 15, 2012*

1 pertaining to Dominion Virginia Power’s petition for approval to implement demand-side
2 management (“DSM”) programs.

3 **Q. What is the purpose of your testimony?**

4 A. The purpose of my testimony is to provide a critique and assessment of Virginia Electric
5 and Power Company’s (“the Company” or “DVP”) Integrated Resource Plan (“IRP”) and
6 make comparisons of the Company’s IRP processes to industry best practices.

7 **Q. Please summarize your conclusions.**

8 A. My review and assessment of the Company’s IRP leads me to conclude that:

- 9 • The IRP is based on a load forecast that has not been fully explained and may
10 well be over-stated.
- 11 • The IRP does not consider renewable energy resources and energy efficiency
12 resources on an equal basis with supply side options within the Company’s
13 planning models. As a result, customers will likely face higher costs from
14 construction of new nuclear generation, new natural gas generation, and from
15 expensive environmental compliance costs for existing generation assets.
- 16 • The retirement decisions, however, for several coal-fired units are well-
17 justified.
- 18 • The IRP does not include higher energy savings rates from efficiency despite
19 the fact that energy efficiency is a low cost and low risk alternative to supply
20 side options. In fact, forecasted energy efficiency is far less than what could
21 reasonably be achieved and what many other organizations are achieving
22 today.

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Although the Commonwealth of Virginia adopted a voluntary goal of reducing the consumption of electric energy by retail customers by 10 percent by 2022², the Company does not appear to be committed to meeting this goal. Cumulative energy efficiency (less voltage conservation programs) is only estimated to reach 2.38 percent of 2006 load by 2026. This is far less than other investor owned utilities have accomplished in recent years, as explained further below. Had the Company analyzed energy efficiency and renewable energy on an equal basis with traditional supply side options within the Company's planning models, it would have demonstrated to the SCC how the Company could:

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- Take more control over its energy future by cost effectively reducing load growth;
- Reduce customer's energy bills;
- Diversify its risk exposure to potential cost escalations associated with nuclear power;
- Diversify its risk exposure to current and future environmental regulations;
- Help to improve Virginia's environment; and
- Create more jobs.

19

Q. What actions do you recommend the SCC take in this proceeding?

20

A. Because the IRP is deficient in many respects – and because the IRP envisions spending billions of dollars in ratepayer money on new capital expenses in the near future – I recommend that the Commission require the Company to convene a stakeholder committee meeting within 30 days of a Final Order and resubmit a new IRP, with greater input obtained through the stakeholder review process, within 12 months. A more

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² See Virginia General Assembly, 2007 Reconvened Session, Acts of Assembly, Chapter 888, Enactment Clause 3 (approved April 4, 2007).

1 inclusive planning process needs to give all stakeholders and the Company “skin in the
2 game” with regard to the stakeholder committee, which would help to ensure that the
3 Company develops an IRP that is consistent with industry best practices and better
4 coordinated with regional bulk power operators such as PJM. For this process to work,
5 representatives from all interested parties should be invited to participate and meet on a
6 regular monthly basis. At the end of the 12 month planning period, a consensus IRP
7 would be submitted to the SCC for approval. If the committee is unable to develop a
8 consensus IRP, each party retains its original rights to demonstrate to the SCC how the
9 IRP is not in the public interest.

10 **Q. Please describe the characteristics of an IRP that are consistent with industry best**
11 **practices.**

12 **A.** The primary objective of an IRP is to develop a preferred resource plan that can reliably
13 serve forecasted load under a variety of potential scenarios at the lowest present value
14 life-cycle costs. In developing its Preferred Plan, utilities that follow IRP best practices
15 strive to address a host of complex risks in a structured manner that is inclusive and
16 transparent. The process of developing a comprehensive and transparent IRP ultimately
17 makes the IRP more relevant to the sponsoring utility, government agencies, consumer
18 groups and others by considering the expertise and perspectives of all stakeholders with
19 an interest in the future of the electric system. In general terms, a best practices IRP:

- 20 • Determines the electricity needs of the service territory by forecasting probable
21 loads and energy requirements, assuming no incremental interventions on the
22 customer’s side of the meter (i.e., demand side resources);
- 23
- 24 • Examines alternative least cost resource configurations to serve forecasted load by
25 considering all resources, including demand side resources, on an equal basis;

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- Communicates clear objectives about how the sponsoring utility selects resource plans that result in the lowest present value life cycle costs given a range of probable risks and scenarios;
- Clearly describes the methodology for monetizing the value of risks inherent in delivering power to customers such as:
 - Capital expansion and construction delays,
 - Rising construction costs,
 - Interest rate and capital risks,
 - Environmental compliance costs,
 - Price volatility of fossil fuels, and
 - Fossil fuel supply disruptions caused by geopolitical impacts.

With respect to demand side options, best practice IRPs fully analyze the benefits

and costs of:

- DSM life cycle costs and Benefit/Cost ratios;
- Reliability of energy savings (i.e., persistence);
- Cost of saved energy vs. the cost of traditional supply side costs;
- Energy/demand impacts of energy efficiency by characterizing the load shapes of specific energy efficient end uses;
- Environmental benefits such as emissions avoided;
- Customer satisfaction; and
- Risk diversity and operational flexibility.

As I describe in the following sections, the IRP neglects to fully assess a wide range of possible scenarios and associated risks. In contrast to IRP best practices, the Company's IRP has not fully examined alternative resource configurations on a comparable basis with traditional supply side options and has not adequately described its methodological approach. Further, the Company's use of the Ratepayer Impact Measure ("RIM") test is incompatible with industry best practices. As a consequence of these and other shortcomings (described below), the IRP is not reasonable or in the public interest.

1 **Q. The Company relies on RIM to screen energy efficiency programs because the**
2 **Company believes this is necessary to comply with the SCC guidance on DSM**
3 **program cost-effectiveness. Do you agree that RIM should be the primary**
4 **indicator?**

5 **A. No. I have presented my thoughts on the RIM test in PUE-2011-00093 (both direct and**
6 **on the witness stand). In summary, RIM does not effectively capture the overall costs and**
7 **benefits of DSM programs to all customers. It focuses narrowly on short term rate**
8 **impacts rather than longer term economy-wide benefits. Even though DSM programs**
9 **could lead to slightly higher rates in the short term due to the reduction in energy sales,**
10 **energy bills trend lower for participants and non-participants alike because consumption**
11 **is reduced by more than the rate impacts and costly supply side resources are postponed.**
12 **As a consequence, DSM programs result in positive benefit-cost ratios when analyzed**
13 **from the customer, utility, and broader economic perspectives. This is so for three**
14 **primary reasons. First, the levelized cost of DSM is half the cost of marginal supply side**
15 **options. Second, DSM postpones (sometime indefinitely) the need to build costly**
16 **transmission and generation. Third, DSM creates what is referred to as Demand**
17 **Reduction Induced Price Effects or DRIPE.**

18 **I believe RIM is a flawed test and, if used as a bright-line requirement for DSM**
19 **programs, will result in higher electricity costs for consumers over time. Rather than**
20 **foster energy efficiency, focusing on RIM may actually encourage consumption when**
21 **average costs are less than marginal supply costs, leading to higher MWh sales,**
22 **transmission congestion, and expensive environmental compliance costs. Eventually,**

1 average costs rise – often abruptly – when new supply assets and pollution controls are
2 placed in service. For these reasons, most states rely on the Total Resource Cost (TRC)
3 test as the primary indicator for screening DSM programs. More recently, many DSM
4 experts and analysts are moving toward greater emphasis on the Utility Cost Test as well.

5 **Q. How do you know that most states place more weight on TRC results for the**
6 **purpose of screening DSM programs?**

7 A. According to a recent survey of 41 states, the American Council for an Energy Efficient
8 Economy (“ACEEE”) found that, with respect to the primary test for assessing efficiency
9 program cost-effectiveness:³

- 10 • 29 states use the TRC test;
- 11 • 6 states use the Societal Cost Test (SCT);
- 12 • 5 states use the Program Administrator Cost Test (PACT); and
- 13 • 1 state (Virginia) uses the RIM test.⁴

14 Although the survey did not specifically examine the reasons why most states
15 place more weight on the TRC test, it is likely due to the fact that the TRC test measures
16 regional net benefits over the long term. Energy efficiency programs that pass the TRC
17 will reduce the total cost of energy in the region, even if rates increase. In short, the TRC
18 test focuses on long term economy-wide benefits, not short term rate impacts. According

³ ACEEE, *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs*, at 60 (Feb. 2012).

⁴ On advice from counsel, I understand that revised Va. Code § 56-576 will require a re-formulation of how Virginia uses the cost-effectiveness tests, since under the new law the Commission is required to include an analysis of four tests (TRC, RIM, Participant, and Utility Cost) and the law specifically provides that “a program or portfolio of programs shall not be rejected based solely on the results of a single test.” See Virginia General Assembly, 2012 Session, Acts of Assembly, Chapter 210 (effective March 10, 2012).

1 to NAPEE, the TRC test is the appropriate test from a regulatory perspective when
2 evaluating long term integrated resource plans.⁵

3 **Q. Above, you state that DRIPE provides for positive societal benefits. Please explain**
4 **DRIPE and how it is relevant here.**

5 A. DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy,
6 relative to the prices forecast in a business-as-usual scenario, resulting from the reduction
7 in quantities of capacity and energy required from those markets due to the impact of
8 efficiency and/or demand response programs. Thus DRIPE is a measure of the value of
9 efficiency in terms of the reductions in wholesale prices seen by all retail customers in a
10 given period. DRIPE is relevant here because, while it is typically small in percentage
11 terms, when applied to all energy and capacity being purchased in the market, it translates
12 into large absolute dollar amounts. This provides a potentially large offsetting benefit to
13 the costs of delivering efficiency programs, one that applies to both participants and non-
14 participants. To the extent that the Commission is concerned about the impacts of DSM
15 on non-participants, DRIPE is a real benefit to these customers and it is not currently
16 captured in any of the cost-effectiveness tests used by the Company to assess possible
17 DSM programs and portfolios for the IRP.

18 **Q. Do you have specific areas of concern with the IRP as presented by the Company,**
19 **and if so, what are they?**

20 A. There are a number of concerns that the Company should address before the SCC issues a
21 decision in this case. The issues include:

⁵ NAPEE, *Guide to Resource Planning with Energy Efficiency*, at 5-3 (Nov. 2007).

- 1 • Transparency—in its current state, the IRP lacks sufficient details to fully assess
2 the impacts of the risks on the four plans;
3
- 4 • Risks—the IRP neglects to identify or analyze a number of risks that could
5 increase consumer costs over time; and
6
- 7 • Biases—the Company’s IRP process reflects an apparent bias toward supply side
8 options at the expense of cost effective energy efficiency resources and renewable
9 energy resources.
10

11
12 **THE IRP LACKS TRANSPARENCY**
13

14 **Q. Are there particular areas of the Company’s analysis that you feel lack
15 transparency, and if so, what are they?**

16 **A.** Yes, the IRP lacks transparency in the area of load forecast. Despite the Company’s
17 claims to the contrary in its Reply Comments,⁶ it has provided relatively little in the way
18 of concrete information to support the load forecast. The Company cites Appendices 2A
19 through 2I of the IRP, yet, while these provide a number of data points, they contain little
20 to no information regarding the key assumptions driving the load forecast. Most of these
21 appendices reflect the *outputs* of the modeling effort, rather than the inputs. Appendices
22 2A through 2C present historic and forecast sales for Dominion in total and for Virginia
23 and North Carolina customers separately. Appendices 2D and 2F present the total
24 customer count for these same three groupings. Both the customer counts and forecast
25 sales are developed from other inputs cited by the Company, such as “historical data on
26 Virginia housing starts, employment and unemployment rates, and income.” (Reply
27 Comments, at 11.) In the IRP and the Reply Comments, DVP has presented a few point

⁶ Reply Comments of Virginia Electric and Power Company, PUE-2011-00092 (filed Dec. 16, 2012) (hereinafter “Reply Comments”).

1 estimates of forecast growth in Gross State Product and per-capita information, and
2 several qualitative and comparative statements regarding Virginia's economic outlook as
3 compared to other states and regions. However, a number of data sets regarding the
4 Company's forecasted growth and economic outlook are missing or unclear.

5 **Q. What data related to the load forecast should the Company have provided or**
6 **explained better in the IRP?**

7 A. To start, while the Company cites to Moody's Economy.com as its source of economic
8 data, it makes no reference to when these data were obtained, when the forecasts were
9 generated, or the period to which they are applicable. The Company also does not
10 indicate whether the data represent a most-likely point estimate, the median or average of
11 a published range, a selected scenario among many that are available, or other
12 information that would allow the reviewer to assess the reasonableness and applicability
13 of the assumptions ultimately used to create the load forecast.

14 **Q. Do you believe that the Company's load forecast is overstated?**

15 A. I have several concerns about the forecast. First, DVP claims that because its forecast is
16 lower than PJM's forecast, it should be viewed as conservative. (Reply Comments, at
17 14.) Yet outside analysts have recently concluded that PJM should work to improve its
18 forecasting efforts. Citing the importance of the load forecast to PJM's reliability
19 analysis, Synapse Energy Economics notes that "the link between economic growth and
20 increases in electricity demand is weakening" and that as a result of this, and increases in
21 savings from efficiency and other demands-side resources, "the peak load forecast may

1 well flatten or diminish over time.”⁷ On this point, it is worth noting that Commission
2 Staff, through testimony filed in the Company’s most recent rate case, observed that
3 “peak loads in the Dominion Zone have remained virtually *flat* for the past 7 years.”⁸

4 Second, many of Dominion’s past energy forecasts have been overly optimistic.
5 In the Company’s most recent rate case, Environmental Respondents introduced several
6 sets of load forecast data obtained from the Commission’s Division of Economics &
7 Finance.⁹ The four forecasts for annual energy load in these exhibits have compound
8 annual growth rates (“CAGR”) of between 2.0 and 2.9 percent, with an average of 2.3
9 percent. The Exhibits also show that the *actual* CAGR from 1992 through 2010 was 1.75
10 percent. The Company consistently overestimates load growth, to the tune of over 0.5
11 percent per year. Over a 10 year period, this is more than 5.6 percent excess load, which
12 represents nearly the *entire* output of the recently approved Warren County Combined
13 Cycle plant. With six proposed Combustion Turbines (CTs), two additionally proposed
14 Combined Cycle plants (CCs), and the North Anna Unit #3 in the Company’s Preferred
15 Plan, these forecasting issues are especially noteworthy.

16 Third, the Company’s response to Environmental Respondents’ comments about
17 discrepancies between the growth rate in population and the growth rate in customers
18 points out a potential flaw in the forecast. DVP claims that one explanation for this
19 difference is the possibility that the higher growth rate in customers may be based on
20 individuals purchasing second homes. (Reply Comments, at 13.) In such a case, the load

⁷ Peterson, P., et al. Synapse Energy Economics, *PJM System Planning: Enhancements for the 21st Century*, (June 20, 2011).

⁸ Testimony of Howard Spinner, PUE-2011-00027, Exhibit 95, at 11 (pre-filed Aug. 15, 2011) (emphasis in original).

⁹ See Exhibits 96 through 101, PUE-2011-00027 (containing data from Dominion’s prior forecasts).

1 increase from the additional “customer” represented by the second home clearly will not
2 increase the total load by an amount equal to the load from a full-time residence.

3 Electricity consumption is clearly a function of the number of dwellings *and* the number
4 of individuals in those dwellings. To the extent that the number of individuals per
5 customer account is decreasing as a result of second-home ownership, extrapolating
6 previous per-customer consumption patterns into the future will overstate the load
7 forecast.

8 Fourth, a quick review of material provided by the Company in response to Staff
9 Interrogatory 4-9 revealed surprising assumptions regarding the energy consumption of
10 household appliances. The values reported on page 9 of the *Virginia Power Peak
11 Demand and Energy Sales Forecast Model Documentation* appear to be out-dated and
12 overstated. For example, the assumed consumption of a refrigerator seems to reflect units
13 from approximately 20 years ago. Current units use about half of the reported value.
14 Given that the forecast is predicated on determining how load will grow with increases in
15 population and customers, overstating the consumption of appliances, even as an average
16 of all currently installed units, will bias the load forecast high.

17
18 **IN ITS CURRENT STATE, THE COMPANY’S PREFERRED PLAN SUBJECTS**
19 **CUSTOMERS TO UNNECESSARY AND POTENTIALLY COSTLY RISKS.**
20

21 **Q. Please explain how the preferred, or base, plan subjects customers to unnecessary,**
22 **and potentially costly, risks.**

23
24 **A.** In short, the Preferred Plan does not address a number of risks and costs associated with
25 nuclear power and does not comprehensively assess potentially significant environmental

1 compliance costs. Had the IRP fully addressed these risks and costs, the Preferred Plan
2 would have incorporated far more cost effective energy efficiency and renewable energy
3 resources in its IRP.

4 **Q. Ok, let's discuss each of these issues separately. Starting with nuclear risks, please**
5 **state why the IRP has not sufficiently incorporated risks and costs that are**
6 **associated with nuclear power.**

7 A. Although the Company has not yet fully committed to building the North Anna Unit #3
8 nuclear facility, the Company has included the unit in the Preferred Plan with an
9 estimated completion date in 2022. According to the Company, North Anna #3 would
10 provide the region with "much needed baseload capacity." (IRP, at 71.) What the
11 Company neglects to describe in its IRP, however, are the range of risks that are
12 associated with nuclear power. The risks include the following¹⁰

- 13 • **Technology risk**, which stems from the fact that the new generation of nuclear
14 reactors are uncertain, especially when considering that cost estimates for new
15 nuclear reactors have increased dramatically over the past five years (doubling or
16 tripling), while the cost of efficiency programs and renewable energy
17 technologies (wind and solar) are declining and availability is rising.
- 18 • **Policy risk**, which stems from the fact that federal policy is in flux. Climate
19 policy may create a very substantial mandate for energy efficiency and
20 renewables, which will dramatically shrink the need for new, nonrenewable, large
21 baseload generating capacity. Further policies that may reduce the need for large
22 baseload generating units include revised building codes, appliance efficiency
23 standards, and increases in funding for weatherization retrofitting of buildings.
- 24 • **Regulatory risk**, which stems from the regulatory lag. Because of the complexity
25 of nuclear power, regulators move slowly in evaluating reactors or authorizing
26 their cost recovery. The fact that these are complex designs has made completing
27 them difficult and standardization of plant designs has proven challenging.
28
29

¹⁰ Cooper, M., *All Risk, No reward for Taxpayers and Ratepayers, the economics of subsidizing the "Nuclear Renaissance" with Loan Guarantees and Construction work in Progress*, (Nov. 2009).

- 1
2 • **Marketplace risk**, which stems from the effects of the most recent recession and
3 anemic economic growth. These conditions have not only resulted in the largest
4 drop in electricity demand since the 1970s, but also appear to have caused a
5 fundamental shift in consumption patterns that will dramatically lower the long-
6 term growth rate of electricity demand. On the supply side of the market, there are
7 a host of renewable-energy alternatives that have lower cost to meet the need for
8 electricity in a carbon-constrained environment and there is growing confidence
9 in the cost and availability of these alternatives.

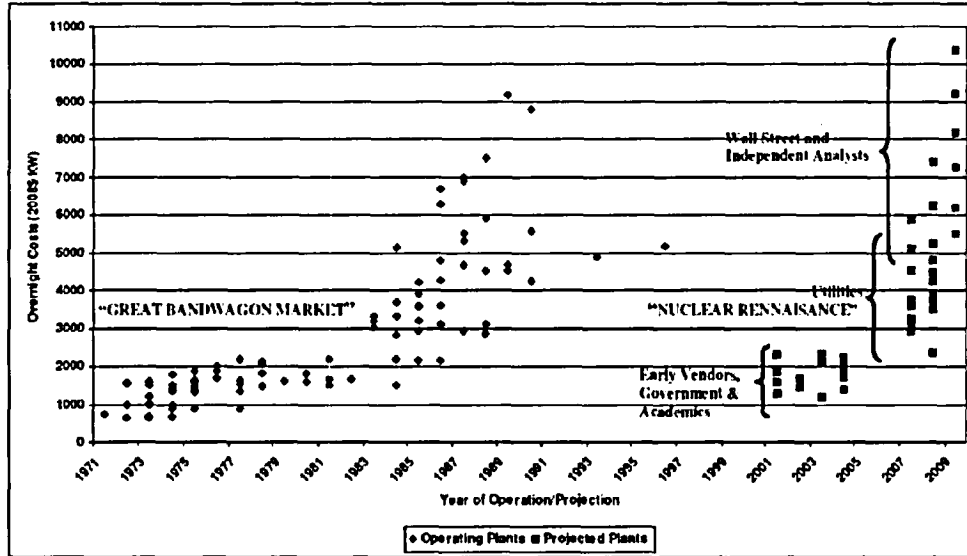
10
11 All of the above risks create substantial financial risks for ratepayers. Financial
12 risks manifest themselves in the form of higher cost of debt, higher equity risk premiums,
13 limited access to short term capital, diminishing operating cash flows, and a weakened
14 balance sheet. In turn, the destabilizing effects of these financial risks result in postponed
15 maintenance, deteriorating reliability, and higher rates.

16 **Q. You mention dramatic increases in cost estimates for new nuclear generation. What**
17 **evidence of this can you provide?**

18 **A.** A recent report by Synapse Energy Economics shows both historical and recent trends in
19 nuclear capacity construction costs.¹¹ The figure below summarizes a large dataset and
20 shows that during both the historic nuclear construction period of the 70s and 80s and the
21 more recent industry-labeled “nuclear renaissance,” overnight construction cost estimates
22 have risen dramatically. While the final cost of North Anna #3 cannot now be accurately
23 predicted, there is overwhelming evidence that the overall cost trend is increasing. At the
24 same time, we know that the overall cost trend for renewable energy is decreasing and
25 energy efficiency is flattening out at less than half the cost of nuclear power.

¹¹ Chang, M. et al. *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S.*, Synapse Energy Economics (Oct. 2011) (hereinafter “Synapse Nuclear Energy Report”).

Exhibit A-1. Nuclear Reactor Overnight Cost Estimates Taken from *Economics of Nuclear Reactors: Renaissance or Relapse*



1

2 **Q. What are the implications of including the North Anna #3 unit in the Company's**
3 **IRP?**

4 **A.** By not fully monetizing the costs of the above-noted risks, the Company has neglected to
5 compare the risk-adjusted cost of nuclear power to alternative solutions. At the same, the
6 Company has crowded out investments in lower cost resources such as energy efficiency
7 and renewable energy because the Company has access to limited amounts of capital at
8 current interest rates. Had the Company monetized these risks, the Commission would
9 have been able to evaluate the range of nuclear related costs and decide whether
10 increasing investments in DSM would be a better course of action.

11 **Q. Do you have evidence that nuclear power plants cost more than the estimates**
12 **reported by DVP?**

1 A. While it is difficult to make cost comparisons of nuclear reactors, the table below, from
2 the same Synapse study referenced above, provides additional insight into the range of
3 possible costs based on independent studies of nuclear plants.¹²

| <u>Plant</u> | <u>Low</u> | <u>Medium</u> | <u>High</u> |
|--------------|------------|---------------|-------------|
| Levy | \$8,286 | \$9,529 | \$10,771 |
| Vogtle | \$5,388 | \$10,775 | \$16,163 |

4 Source: Synapse Nuclear Energy Report, App. B-1

5 This independent analysis of nuclear costs should be used to scrutinize the
6 Company's estimates of the North Anna #3 unit.¹³ There are several plausible reasons for
7 the differences between the table above and Dominion's calculations: different reactor
8 models, state-specific siting requirements, greenfield vs. expansion units, financing costs
9 and many others. Such cost differences are, of course, highly relevant for planning
10 purposes but what may be even more important to the Commission at this point in time is
11 that the IRP does not raise a host of relevant questions, such as:

- 12 • What are the specific events that could significantly increase the cost of
13 building the North Anna #3 unit?
- 14 • How likely are these events to happen in the future?
- 15 • How significant are the above risks (i.e. the dispersion of possible outcomes)?
- 16 • Should ratepayers bear the cost of such risks when viable, cost-effective
17 alternative solutions have not been fully evaluated but are known to
18 successfully support efforts to bolster reliability?
- 19 • Should ratepayers bear the cost of such risks when viable, cost-effective
20 alternative solutions have not been fully evaluated but are known to
21 successfully support efforts to bolster reliability?
- 22

¹² See Synapse Nuclear Energy Report.

¹³ The Company has provided two different values for capital cost of the North Anna #3 unit. The IRP provides one value in Confidential/Extraordinarily Sensitive Appendix 5B, but the Company presented a different cost in the Extraordinarily Sensitive response to Commission Staff Interrogatory 3-7.

1 **Q. Moving on to environmental issues, please explain how the IRP evaluated the**
2 **potential environmental compliance costs of the Company's existing fleet of coal**
3 **plants?**

4 **A.** Environmental regulations and related compliance costs must be factored into an IRP. In
5 that sense, the Company's IRP provides minimal information regarding a number of
6 important environmental compliance cost considerations that it will face in the near and
7 long term, especially since they could impact existing coal-fired generation.

8 According to a recent PJM assessment of the potential impact of two
9 environmental regulations,¹⁴ the Cross State Air Pollution Rule ("CSAPR") and the
10 Mercury and Air Toxics Standards ("MATS") Rule¹⁵, environmental compliance with
11 those rules will require the installation of some combination of the following controls: 1)
12 sulfur dioxide (SO₂) controls such as limestone-based flue gas desulfurization (FGD) or
13 dry sorbent injection (DSI); 2) nitrogen oxide (NO_x) controls such as selective catalytic
14 reduction (SCR) or selective non-catalytic reduction (SNCR); 3) activated carbon
15 injection (ACI) for mercury; and 4) a fabric filter (also known as a baghouse) for the
16 particulates associated with heavy metals and the use of ACI or DSI. Using the same
17 retrofit cost models as used by EPA in its analysis of the CSAPR and NESHAPs rules,
18 PJM estimates the average installed costs of these retrofits in PJM to be \$802/kW for an
19 FGD, \$369/kW for an SCR, \$172/kW for an ACI and a fabric filter, and \$118/kW for

¹⁴ PJM Interconnection, *Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants*, (Aug. 26, 2011) (hereinafter "PJM CSAPR and NESHAPS Report").

¹⁵ The PJM CSAPR and NESHAPS Report refers to the MATS Rule as the National Emissions Standards for Hazardous Air Pollutants (NESHAPs). Invoking another acronym, "MACT" for Maximum Achievable Control Technology, the MATS Rule is also often called the Utility MACT Rule.

1 DSI.¹⁶ PJM also assumes that for many coal facilities, especially those that have been in
2 operation for more than 40 years, one or more the above noted retrofits will be
3 necessary.¹⁷ Compared to the cost of peak energy reductions from energy efficiency and
4 demand response measures, as highlighted in the table below, retrofitting coal facilities
5 will be a costly investment that will likely drive up rates for consumers.

| Utility | Cost of savings/kW | Average Coal Compliance Costs/kW | |
|------------------------|--------------------|----------------------------------|-------|
| Interstate P&L (MN) | \$774 | FGD | \$802 |
| Excel (MN) | \$457 | SCR | \$369 |
| Excel (CO) | \$367 | ACI | \$172 |
| Arizona Public Service | \$447 | DSI | \$118 |
| Mid American (IA) | \$616 | | |

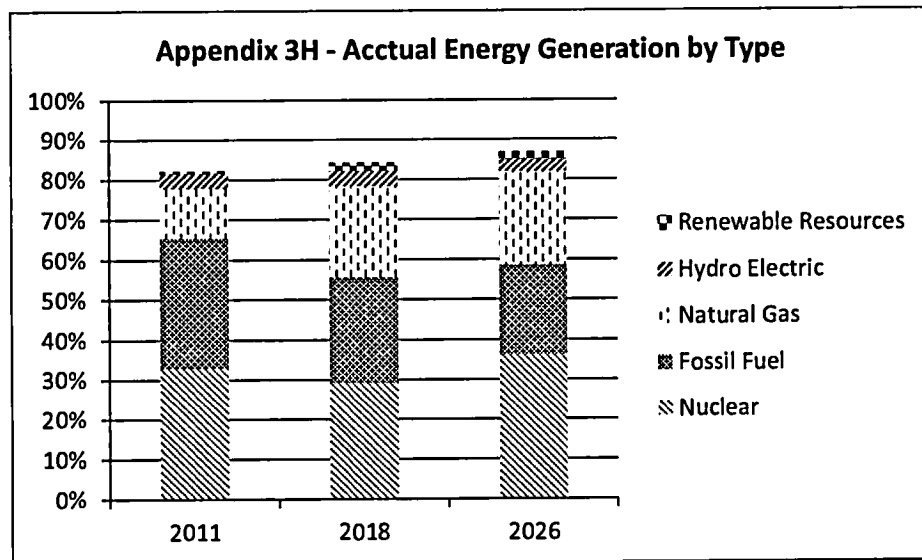
6
7 As the table above demonstrates, PJM's estimate of FGD retrofit costs alone
8 exceeds the cost of peak savings incurred by several of the top energy efficiency
9 programs operated by investor-owned utilities. The cost of multiple retrofits will greatly
10 exceed the cost of efficiency and demand response. Upon reflecting on all of the existing
11 and future environmental compliance cost issues, it is clear that the IRP has not
12 sufficiently stress-tested the ranges of potential economic risks that could adversely
13 impact the cost of continuing to operate its existing coal fleet.

14 **Q. Why should these omissions in DVP's economic analysis be of concern to the**
15 **Commission?**

¹⁶ See PJM CSAPR and NESHAPs Report, at i.

¹⁷ See *id.* at ii.

1 A. The Company will continue to rely on coal for a substantial portion of its generation over
2 the planning period.¹⁸ The chart below demonstrates that the Company will continue to
3 rely on fossil fuels (both coal and natural gas) facilities to generate nearly half of total
4 system requirements despite the expectation of rising compliance costs.



5
6 **Q. How should the Company's environmental compliance needs be factored into the**
7 **IRP?**

8 A. According to a recent PJM report, environmental compliance costs are not only
9 significant but are leading many generators to re-think the economics of coal plant
10 operations, especially plants that have been operating for 40 or more years and have
11 capacity of 400 MWs or less.¹⁹ The report highlighted that economic conditions under
12 which retrofit and retirement decisions are being made include the following:²⁰

- 13 • Reduced natural gas/coal price spreads from \$5-\$7/MMBtu in 2006-
14 2008 to \$2-\$3/MMBtu in 2009 that are forecast by the Energy

¹⁸ See IRP Appendix 3H.

¹⁹ See PJM CSAPR and NESHAPS Report at ii.

²⁰ See *id.* at i-ii.

1 Information Administration to continue until 2016. This reduces the net
2 energy market revenues available to cover the costs of environmental
3 retrofits.
4

- 5 • Lower forecast average hourly energy demand that leads to lower cost
6 resources on the margin setting price and lower net energy market
7 revenues available to cover the costs of environmental retrofits.
8 Moreover, less efficient units will not run as often, further eroding net
9 energy market revenues available to cover retrofit costs. This reduces the
10 net energy market revenues available to cover the costs of environmental
11 retrofits.
12

- 13 • Over the past four years, the combination of reduced natural gas/coal
14 price spreads and lower demand have already resulted in capacity factors
15 that have fallen from 65 percent in 2007 to about 40 percent in 2010 for
16 coal-fired units less than 400 MW and more than 40 years old. At the
17 same time, coal-fired units greater than 400 MW, regardless of age, have
18 maintained relatively constant capacity factors in the face of reduced
19 hourly demands and reduced fuel price spreads.
20

21 Overall, the decline in the gas/coal price spread and average hourly demand have resulted
22 in declining net energy market revenues for all coal capacity, but net revenues remain
23 lowest for coal-fired units less than 400 MW and more than 40 years old. According to
24 the information provided in Appendix 3A of the IRP, the following units appear to meet
25 these conditions: Brema 3 and 4, Chesapeake 1 through 4, Chesterfield 3 through 5, and
26 Yorktown 1 and 2. Dominion has identified all of these units as being slated for retrofit,
27 repowering, or retirement in the next ten years. Given the factors outlined above, the
28 retirement decisions appear to be well-justified.

29 **Q. Does the Company's IRP take any of the above concerns into consideration?**

30 **A.** As I mentioned, Dominion's decision to retire certain units is a proper response to these
31 concerns. At the same time, while the IRP mentions several potential environmental
32 compliance needs in Figure 3.1.3.1 (IRP, at 21), the lack of clarity as it relates

1 environmental compliance *costs* is troubling. The Company should transparently
2 demonstrate whether it has factored in foreseeable future regulation so the Commission
3 and the public will have the information necessary to assess the costs associated with
4 various supply side resources and compare those costs to alternative resources. Increasing
5 transparency will translate into an improved ability to provide low cost, low risk power to
6 customers.

7 **Q. What evidence does the IRP provide that energy efficiency is a lower cost solution**
8 **relative to the levelized cost of the traditional supply side resources?**

9 A. The IRP provides a forecast of the dispatch prices for supply side resources in the
10 Company's Extraordinarily Sensitive exhibit attached as a response to Commission Staff
11 Interrogatory 3-7. In addition, the Company's Confidential response in the DSM docket
12 (PUE-2011-00093) to Staff Interrogatory 5-43 provides important data for on-peak
13 energy price forecasts over the planning period. Transmission, distribution, and other
14 ancillary costs will also add to the cost of delivered electricity. Depending on future
15 circumstances, dispatch costs and spot energy prices could easily be even more expensive
16 than predicted. Furthermore, both types of purchases are contingent on available capacity
17 at the precise time when DVP needs the power and at a competitive cost.

18 Rather than subject its customers to potentially volatile market events and costs,
19 the Company should instead exert more control over its resources by implementing
20 aggressive energy efficiency programs, which typically cost in the range of \$20 to \$40
21 per MWh (levelized). To provide a hedge against rising fuel costs for coal and other
22 fossil fuels, and to better insulate ratepayers from rate increases associated with

1 environmental compliance costs, the Company should also place greater emphasis on
2 renewable options, especially in the later years of the IRP where many future, unnamed
3 and unidentified CTs and CCs threaten to increase the Company's reliance on fossil fuels.
4 Last, I note the contrast between DVP's assumptions and PJM's assessment that energy
5 efficiency and demand response may provide lower cost alternatives to achieve resource
6 adequacy.²¹

7
8 **DVP'S IRP IS BIASED TOWARD NON-RENEWABLE, SUPPLY SIDE OPTIONS**
9 **AT THE EXPENSE OF COST EFFECTIVE ENERGY EFFICIENCY AND**
10 **RENEWABLE ENERGY RESOURCES.**
11

12 **Q. Why have you concluded that the Company's IRP is biased toward non-renewable,**
13 **supply side options and fails to treat energy efficiency resources on an equal basis?**

14 **A.** There are indications in support of my argument peppered throughout the IRP, the most
15 telling of which is the Company's statement on page 81:

16 *"The DSM TRC Test Analysis illustrates that the addition of the three*
17 *programs to the portfolio of DSM programs decreases total system utility*
18 *costs (as shown by the 0.26% increase in net benefits to the Utility test),*
19 *while increasing rate impacts to non-participants (as shown by the 2.68%*
20 *decrease in net benefits to the RIM test as compared to the 2011 Plan)."*
21

22 Inclusion of the three additional programs would have also resulted in a 2 percent
23 increase in net economy-wide benefits under the TRC test, according to the Company's
24 Figure 5.5.6.1.

²¹ PJM CSAPR and NESHAPS Report, at iv.

1 The fact that the Company dramatically reduces investment in energy efficiency
2 in the out years of the IRP also indicates that the Company is biased toward non-
3 renewable, supply side assets. For example, Figures 1.4.2 and 1.4.3 show that the
4 amount of capacity and energy met through DSM resources grows incrementally in the
5 early years of the IRP, but then remains flat through the latter half of the study period.²²
6 Had the Company assessed energy efficiency on a comparable basis with supply side
7 resources, the Company would have determined that lower cost efficiency programs can
8 easily displace greater amounts of load than is currently anticipated.

9 Another indication is that 46 percent of forecasted energy savings from approved
10 and future DSM programs come from a “voltage conservation” program. Savings
11 attributable to “voltage conservation” increases to a high of 59 percent of total DSM
12 savings in 2022, offsetting decreases in annual incremental savings from the Company’s
13 conventional energy efficiency programs. While voltage conservation may have merit, it
14 is not a widely accepted energy efficiency program that is offered by efficiency program
15 administrators in other jurisdictions. The program is instead an AMI demonstration
16 project that should be treated as a capital investment and subject to a prudency review
17 just like any other addition to rate base..

18 **Q. What do the above-noted approaches to IRP planning tell you about the Company’s**
19 **biases?**

20 **A. The Company does not properly value energy efficiency resources, leaving significant**
21 **amounts of cost-effective efficiency undeveloped over the planning horizon. As a**

²² For more detailed information, see Confidential Appendix 6D to the IRP.

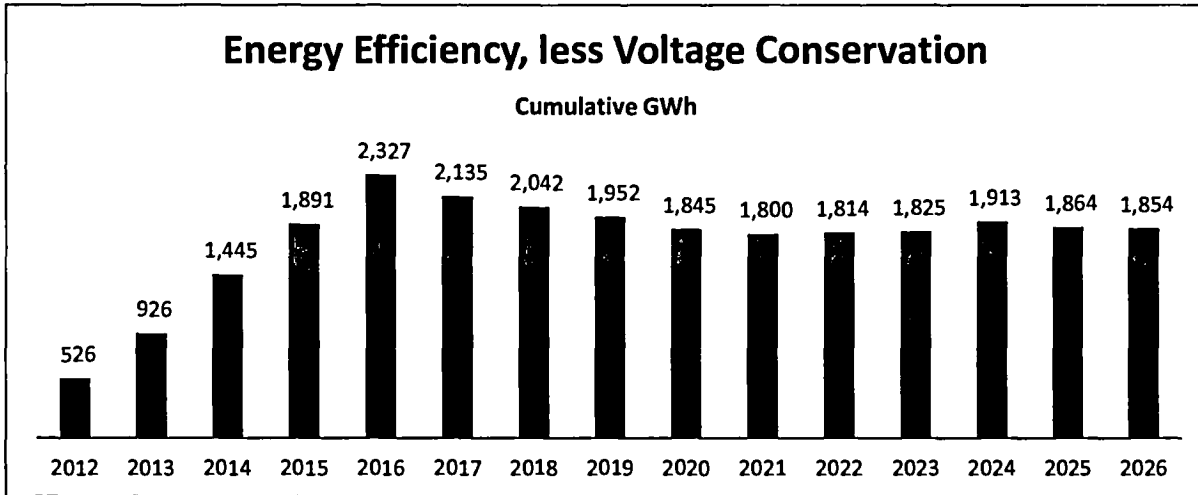
1 consequence of its approach, the Company's default reaction is to plan on building
2 supply assets first and then layer into the plan marginal amounts of energy efficiency.

3 **Q. If the Company treated energy efficiency on an equivalent basis as supply side**
4 **resources, could the Company realistically acquire greater amounts of low cost**
5 **energy efficiency than currently planned?**

6 **A. Absolutely, yes. As described in more detail in the sections below, several other**
7 **organizations regularly develop program plans to achieve higher cumulative and annual**
8 **rates of savings than the Company's forecasts. In this IRP, the Company anticipates**
9 **cumulative energy savings, net of voltage conservation, of 1,854 GWh in 2026,**
10 **approximately 2.38 percent of 2006 load, which is far short of the Commonwealth's 10**
11 **percent efficiency goal that is supposed to be achieved by 2022. This means that annual**
12 **incremental savings will be only 0.12 percent on average. The Company's forecasted**
13 **cumulative and annual incremental savings, net of voltage conservation, are exceptionally**
14 **low compared to several other utilities, as highlighted in the tables below.**

15 **Q. Before you compare DVP's energy efficiency savings to other utilities, please**
16 **provide your observations about the forecasted rate of savings in the IRP.**

17 **A. As the graph below demonstrates, DVP's projected cumulative savings, net of voltage**
18 **conservation, grows initially up to 2016 and then decreases before flattening out.**



1
2 The Company stated that its DSM plans assume full “market saturation” after 5
3 years (Reply Comments, at 16, footnote 15), but this is clearly not true given the
4 relatively minor total savings forecast to be acquired in that time as compared with other
5 jurisdictions.

6 Without sustained funding, additional cost effective energy efficiency measures
7 will not be installed in the out years to replace the deterioration in savings from
8 previously installed efficient measures. Had the Company assessed energy efficiency
9 resources in accordance with best practices, funding would be sustained over the
10 planning period and annual incremental savings would at least maintain similar levels as
11 from 2012 through 2016, or even increase to 1.0 percent of load or higher.

12 **Q. What level of funding for DSM would you recommend?**

13 **A.** Without making a specific recommendation, I note the following: the Company recently
14 projected that from 2011 to 2015, it needed to invest \$7.4 billion in new generation,

1 transmission, and distribution facilities.²³ The level of DSM investment included in the
2 IRP is just a small fraction of that amount.²⁴ Of that, a substantial portion is for the
3 Voltage Conservation Program, which is not an end-use efficiency program but rather a
4 capital investment in AMI. Proposed spending on true efficiency is miniscule compared
5 to the overall investment.

6 **Q. What do these facts demonstrate to you?**

7 A. As explained above, the sharp reduction in planned efficiency reflects an aversion to IRP
8 and DSM best practices. But even more worrisome to me is that the sharp reduction
9 reflects the Company's lack of commitment to address its customers concerns over
10 energy bills and the environment. The Company has not included reasonable amounts of
11 energy efficiency in its long-term resource plan.

12 In my review of numerous energy efficiency and IRP documents, I am unaware of
13 any utility with a serious commitment to energy efficiency that assumes that such a small
14 quantity of efficiency savings over 5 years represents "market saturation."

15 **Q. Why is Dominion's assumption of "market saturation" incorrect?**

16 A. New cost-effective savings can be acquired well into the future from both deeper
17 penetration into the market for existing technologies and from a variety of new sources,
18 such as the following:

- 19 • New technologies such as LEDs;
- 20 • Cost reductions as seen in consumer electronics and appliances;
- 21 • Improved building designs, material and construction practices; and
- 22 • Innovative program implementation strategies such as on-bill financing.

²³ See Direct Testimony of Paul D. Koonce, PUE-2011-00027, Exhibit 5, at 5 (pre-filed Mar. 31, 2011).

²⁴ The percentage of DSM investment compared to other capital expenditures can be determined using the data in Confidential Appendix 6D to the IRP.

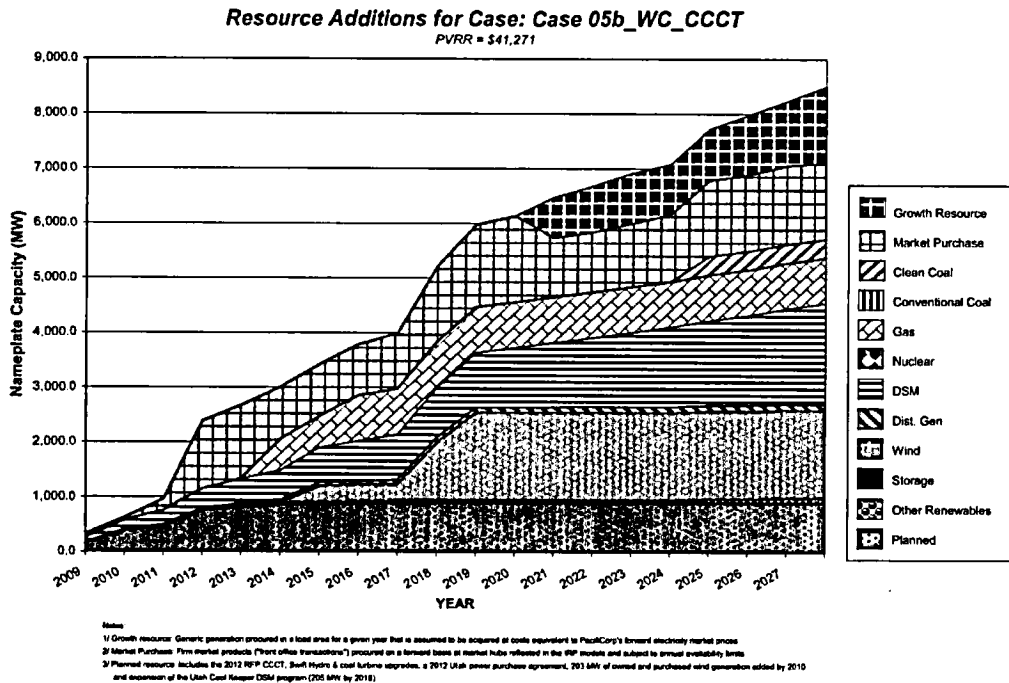
1
2 The long-term durability of energy efficiency savings is suggested by a study
3 commissioned in Rhode Island, a state that has been aggressively pursuing efficiency
4 resources for several years. According to KEMA (the same DSM consultant used by
5 Dominion), Rhode Island could continue to achieve increasing levels of efficiency,
6 saving as much as 29 percent of projected energy demand over the next decade at a
7 savings of \$1.85 billion for ratepayers.²⁵ As a result, the latest Rhode Island energy
8 efficiency plan filed with the state's Public Utilities Commission aims to double annual
9 energy savings over the next three years, from approximately 1.2 percent currently to 2.5
10 percent by 2014.²⁶

11 In California, energy efficiency also has been a mainstay in utilities' long range
12 IRPs. As the graph below demonstrates, PG&E has and will continue to rely on DSM
13 resources to ensure reliability.²⁷

²⁵ KEMA, Inc., *The Opportunity for Energy Efficiency that is Cheaper than Supply in Rhode Island*, prepared for Rhode Island Energy Efficiency and Resource Management Council (Aug. 26, 2010).

²⁶ Based on conversation with Mike Guerard, consultant to Rhode Island's Energy Efficiency Council.

²⁷ PacifiCorp, 2008 Integrated Resource Plan, Vol. I, at 239 and Appendix A, at 31 (May 2009).



1

2

The graph above shows that increasing levels of DSM will be part of PG&E's resource mix well into the future, and shows no sign of only short-term growth followed by stagnation, as DVP's IRP does.

3

4

Q. Earlier in your testimony, you argue that several organizations regularly develop program plans to achieve much higher cumulative and annual incremental savings than forecasted in this IRP. Please provide additional information about the rate of savings achieved in 2010 by the top performing energy efficiency program administrators.

5

6

A. As the table below demonstrates, several organizations have acquired deep savings as a percent of load. Many of the organizations have been providing programs for several years, yet continue to acquire cost effective energy efficiency.²⁸

7

8

9

²⁸ See EIA Form 816 (2010 data).

Direct Testimony of Jeffery Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00092
March 15, 2012

| Organization | Type of Organization | State | Savings as % Load | \$/kWh | EE Spending as % of Revenue | Annual Spending (\$ 1,000) |
|------------------------------------|-----------------------|-------|----------------------|--------|-----------------------------------|----------------------------------|
| United Illuminating Co | Investor Owned | CT | 4.27% | \$0.10 | 7.9% | \$35,779 |
| Glidden Rural Electric Coop | Cooperative | IA | 3.73% | \$0.01 | 1.0% | \$111 |
| Connecticut Light & Power Co | Investor Owned | CT | 3.22% | \$0.07 | 6.4% | \$114,202 |
| Salem Electric | Cooperative | OR | 3.13% | \$0.06 | 8.7% | \$1,928 |
| City of Worthington | Municipal | MN | 2.86% | \$0.01 | 1.9% | \$292 |
| Southern California Edison Co | Investor Owned | CA | 2.64% | \$0.06 | 4.7% | \$457,391 |
| Duke Energy Ohio Inc | Investor Owned | OH | 2.40% | \$0.02 | 1.9% | \$24,075 |
| City of Windom | Municipal | MN | 2.03% | \$0.00 | 1.7% | \$102 |
| City of Stratford | Municipal | IA | 2.03% | \$0.10 | 4.5% | \$27 |
| Pacific Gas & Electric Co | Investor Owned | CA | 1.89% | \$0.18 | 3.4% | \$395,233 |
| City of Burlington-Electric | Municipal | VT | 1.83% | \$0.00 | 3.7% | \$1,819 |
| Austin City of | Municipal | MN | 1.82% | \$0.03 | 2.1% | \$647 |
| Dayton Power & Light Co | Investor Owned | OH | 1.81% | \$0.01 | 1.1% | \$12,157 |
| City of Rockford | Municipal | IA | 1.72% | \$0.18 | 5.4% | \$41 |
| Baltimore Gas & Electric Co | Investor Owned | MD | 1.70% | \$0.06 | 6.0% | \$137,708 |
| Madison Gas & Electric Co | Investor Owned | WI | 1.65% | \$0.02 | 0.7% | \$2,519 |
| City of Wadena | Municipal | MN | 1.60% | \$0.00 | 0.0% | \$0 |
| Rock Rapids Municipal Utility | Municipal | IA | 1.59% | \$0.00 | 0.7% | \$15 |
| City of Chaska | Municipal | MN | 1.56% | \$0.01 | 1.2% | \$307 |
| Rochester Public Utilities | Municipal | MN | 1.54% | \$0.00 | 0.0% | \$0 |
| City of Greenfield | Municipal | IA | 1.52% | \$0.07 | 3.0% | \$104 |
| Tacoma City of | Municipal | WA | 1.50% | \$0.03 | 4.7% | \$12,507 |
| City of Glendale | Municipal | CA | 1.50% | \$0.11 | 2.4% | \$3,693 |
| St Croix Electric Coop | Cooperative | WI | 1.48% | \$0.01 | 2.0% | \$389 |
| Chippewa Valley Electric Coop | Cooperative | WI | 1.43% | \$0.04 | 2.8% | \$341 |
| Sacramento Municipal Util Dist | Political Subdivision | CA | 1.41% | \$0.09 | 2.6% | \$31,253 |
| NorthWestern Corporation | Investor Owned | MT | 1.40% | \$0.08 | 1.7% | \$9,430 |
| Duquesne Light Co | Investor Owned | PA | 1.37% | \$0.07 | 1.4% | \$9,741 |
| Fitchburg Gas and Electric Lig | Investor Owned | MA | 1.35% | \$0.68 | 5.1% | \$2,399 |
| Cascade Municipal Utilities | Municipal | IA | 1.34% | \$0.04 | 2.1% | \$37 |
| Franklin Rural Electric Cooperativ | Cooperative | IA | 1.33% | \$0.04 | 1.5% | \$77 |
| City of Pasadena | Municipal | CA | 1.33% | \$0.05 | 4.6% | \$7,227 |
| PUD No 1 of Clallam County | Political Subdivision | WA | 1.32% | \$0.00 | 4.9% | \$2,161 |
| Salt River Project | Political Subdivision | AZ | 1.32% | \$0.04 | 1.3% | \$31,734 |
| Fairmont Public Utilities Comm | Municipal | MN | 1.31% | \$0.01 | 1.3% | \$184 |
| Puget Sound Energy Inc | Investor Owned | WA | 1.30% | \$0.05 | 3.3% | \$68,494 |
| City of Sabula | Municipal | IA | 1.29% | \$0.11 | 1.1% | \$6 |
| Nevada Power Co | Investor Owned | NV | 1.28% | \$0.04 | 1.7% | \$37,426 |
| Idaho Power Co | Investor Owned | OR | 1.28% | \$0.04 | 4.7% | \$41,341 |
| Idaho Power Co | Investor Owned | ID | 1.28% | \$0.04 | 4.7% | \$41,341 |
| Fort Collins City of | Municipal | CO | 1.24% | \$0.03 | 3.5% | \$3,293 |
| City of Forest Grove | Municipal | OR | 1.23% | \$0.01 | 0.7% | \$91 |
| City of Marquette | Municipal | MI | 1.20% | \$0.04 | 1.2% | \$318 |
| City of Stanton | Municipal | IA | 1.17% | \$0.01 | 1.5% | \$10 |
| City of Marshfield | Municipal | WI | 1.16% | \$0.01 | 0.6% | \$167 |
| Arizona Public Service Co | Investor Owned | AZ | 1.15% | \$0.05 | 1.7% | \$49,832 |
| City of Callender | Municipal | IA | 1.13% | \$0.04 | 0.5% | \$1 |
| Spencer City of | Municipal | IA | 1.13% | \$0.09 | 5.5% | \$512 |
| Tucson Electric Power Co | Investor Owned | AZ | 1.13% | \$0.04 | 1.6% | \$12,972 |
| PUD No 1 of Chelan County | Political Subdivision | WA | 1.10% | \$0.00 | 3.2% | \$1,599 |
| Seattle City of | Municipal | WA | 1.09% | \$0.08 | 4.8% | \$30,113 |
| City of Springfield | Municipal | OR | 1.09% | \$0.02 | 2.7% | \$1,153 |
| Sierra Pacific Power Co | Investor Owned | CA | 1.08% | \$0.04 | 0.9% | \$7,777 |
| City of Waseca | Municipal | MN | 1.07% | \$0.00 | 2.5% | \$166 |
| Northern States Power Co - Minn | Investor Owned | MN | 1.07% | \$0.06 | 3.0% | \$90,093 |
| Eugene City of | Municipal | OR | 1.07% | \$0.08 | 5.3% | \$8,820 |
| City of Anaheim | Municipal | CA | 1.06% | \$0.11 | 1.7% | \$5,435 |
| Interstate Power and Light Co | Investor Owned | IA | 1.05% | \$0.03 | 4.1% | \$7,490 |
| Snohomish County PUD No 1 | Political Subdivision | WA | 1.04% | \$0.07 | 3.8% | \$18,916 |
| Columbus Southern Power Co | Investor Owned | OH | 0.99% | \$0.02 | 1.1% | \$19,938 |

1
2 As the table above highlights, 59 organizations achieved savings equal to or
3 greater than one percent of load annually in 2010. Several of these are organizations that I
4 know have been providing energy efficiency services to their customers for several
5 years.²⁹ While some data are missing and savings do fluctuate from year to year due to a

²⁹ In particular, United Illuminating, Connecticut Light & Power, Southern California Edison, Pacific Gas & Electric, City of Burlington-Electric, City of Austin, Baltimore Gas & Electric, City of Tacoma, Fitchburg Gas and

1 variety of circumstances, the number of companies able to achieve one percent or more
2 on an annual basis is indicative of what can be accomplished with sustained effort and
3 funds.

4 **Q. Are there other organizations not included in the above list of which the
5 Commission should be aware?**

6 A. Yes. There are three additional independent organizations that I am familiar with that
7 deserve attention. They are the Energy Trust of Oregon, NYSERDA and Efficiency
8 Vermont. Each of these organizations has been providing energy efficiency services for
9 10 years or more. Yet, each continues to acquire high rates of energy efficiency on an
10 annual basis.

11 **Q. Are there other regional studies that lead you to conclude that higher rates of
12 energy efficiency potential exist compared to the Company's forecasts?**

13 A. Yes. The SCC may already be familiar with a recent analysis of energy efficiency
14 potential in the South but it is worth noting again for the record. In a study conducted
15 jointly by Georgia Tech and Duke University, the authors determined that the South in
16 general has the economic potential to reduce its energy consumption by 1.5 percent per
17 year and the achievable potential, with vigorous policies, to reduce energy consumption
18 by 1.0 percent per year.³⁰ While the meta-analysis targeted the next decade, the state
19 level studies that accompanied the Georgia Tech/Duke University report examined
20 energy efficiency potential over a 15-20 year time horizon. Those state level studies

Electric, Puget Sound Energy, Arizona Public Service, City of Seattle, Sierra Pacific Power, and Interstate Power & Light have been providing energy efficiency services to their customers for several years.

³⁰ Brown, M. et al, *Energy Efficiency in the South*, Georgia Tech & Duke University (April 12, 2010) available at http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

1 suggested an economic potential of 20-35 percent, consistent with the study's 1.5 percent
2 per year finding, and a maximum achievable potential of 15-30 percent in all but one
3 study.³¹ These findings are well in excess of DVP's average 0.12 percent per year
4 estimates. There is no reason to assume, in my opinion, that DVP's customers could not
5 achieve savings at a rate similar to customers in other jurisdictions.

6 **Q. Does the fact that most of the above-noted states have been leaders in DSM for a**
7 **long time, and that Virginia has relatively little experience in DSM efforts, imply**
8 **that it is not realistic or achievable for Virginia to meet goals similar to other states?**

9 A. No. There is no reasonable basis to conclude that Virginia would be unable to join the
10 ranks of the leading efficiency states noted above for several reasons. First, the
11 marketplace for efficient energy consuming systems is a national market. Efficient
12 lighting systems, HVAC units, motors and other equipment that are available throughout
13 the United States are also available to Virginians. Second, Virginia's climate may offer
14 additional opportunities for potential energy savings. Last, Dominion's residential
15 customers consume approximately 15,000 kWh annually, far higher than the national
16 average, which indicates that there is a massive untapped reservoir of readily accessible
17 and inexpensive energy savings that could be acquired by the Company.

18 **Q. Does the IRP provide the Commission with a complete assessment of the potential**
19 **for renewable energy generation in the Company's service area?**

³¹See Chandler, S. and M. Brown, *Meta-Review of Efficiency Potential Studies and Their Implications for the South, Georgia Tech, Working Paper #51* (Aug. 2009); Brown, M. et al, *Energy Efficiency in the South, Georgia Tech & Duke University* (April 12, 2010). See also Appendix G: State Profiles of Energy Efficiency Opportunities in the South (Virginia) (April 13, 2010), available at http://www.seealliance.org/se_efficiency_study/virginia_efficiency_in_the_south.pdf.

1 A. No, the Company did not provide an assessment of the potential for renewable energy
2 generation in their service area. Instead, DVP relied on state-wide maps provided by the
3 National Renewable Energy Laboratory and the Department of Energy. In many regions,
4 renewable energy costs are continuing to decrease, and becoming cost-competitive with
5 traditional supply side resources when all traditional supply side costs are fully
6 considered. A more detailed review of renewable energy options may have provided
7 greater insight into many of the ancillary benefits associated with in-region renewable
8 energy development. Ancillary benefits include, but are not limited to, increased
9 construction jobs, increased maintenance and operations jobs, enhanced grid stability
10 related to distributed generation, cleaner water as coal-fired electric generation is
11 displaced, and reduced GHG emissions and other pollutants.

12 **Q. The Company argues that the Strategist model did not select the renewable options
13 because they were not cost competitive. How do you respond?**

14 A. The Company's plan has North Anna #3, a multi-billion dollar capacity addition, coming
15 online in 2022. The Company also proposes six new CTs coming online in the later years
16 of the IRP. In fact, the Company's Base Plan has at least one new, supply side resource
17 coming online per year, *every year*, from 2019 to 2026. This is an expensive and
18 ambitious build-out plan that relies entirely on fossil fuels and nuclear. It is reasonable to
19 question whether some of those capacity additions could have been better met through
20 renewable energy resources, which would help diversify the Company's portfolio and
21 guard against fuel price volatility and other risks from large central plant generation.
22 Diversification, hedges against fuel price volatility, and protection against uncertain

1 economic conditions and energy policy contexts all have value that is not captured by the
2 Company's analysis.

3 **Q. The Company, however, notes that it has met the first goal in the Commonwealth's**
4 **Renewable Portfolio Standard ("RPS"), and is on track to meet all future goals.**
5 **Isn't this evidence of the Company's commitment to renewable energy?**

6 **A.** Not at all. As the Commission learned during the Company's most recent rate case (PUE-
7 2011-00027), the Company's compliance plan for the RPS relies overwhelmingly on the
8 purchase of Renewable Energy Certificates ("RECs") and not on the construction of
9 renewable generating resources or on the purchases of renewable energy from merchant
10 providers. According to Public Exhibit 111 from the rate case, DVP needed
11 approximately 1.7 million RECs to meet the first goal under the RPS. The Company met
12 that goal through the purchase of almost 1.2 million RECs which were applied for RPS
13 compliance. An additional 706,000 RECs were purchased and banked for future use
14 toward the RPS goals.³² None of these RECs, of course, did anything to diversify
15 Dominion's portfolio or add renewable energy resources to Dominion's generating fleet.

16 Even more, evidence in the rate case showed that none of these RECs were
17 purchased from onshore wind, offshore wind, or solar facilities. Rather, the RECs came
18 exclusively from conventional hydro units, solid-waste fired units, and woody biomass.
19 Further emphasizing the fact that these REC purchases did little to incent the construction
20 of new renewable generation in Virginia is the fact that the majority of REC-producing

³² See Company's Response to Michel A. King Interrogatories, First Set, PUE-2011-00027 (entered as Exhibit 111 in the proceeding).

1 units (18 of 28) came online prior to the United States' entrance to World War II. No unit
2 supplying RECs was built within the last ten years.³³

3 If anything, the Company's plan for meeting the RPS goals is further evidence
4 that the Company is not seriously committed to putting new renewable energy resources
5 into service as part of its generation portfolio.

6 **Q. You mentioned fuel price volatility and other risks. What do renewable energy
7 resources offer to mitigate these risks?**

8 A. As noted by the Company "Volatility in rates is generally viewed as undesirable." (IRP,
9 at 95.) Because fuel costs are a significant contributor to overall costs (and therefore,
10 rates), the Company assessed both "High Fuel Cost" and "Low Fuel Cost" scenarios.
11 Under the High Fuel Cost scenario, costs for the Preferred Plan increase by nearly 17
12 percent. Because renewable energy sources have no fuel costs, the cost for the Renewable
13 Plan (Plan D) increases by only 13 percent under these conditions.

14 **Q. What assumption did the Company make about fuel costs in the High Fuel Cost
15 scenario?**

16 A. I do not know. The Company did not specify the quantitative changes made to fuel prices
17 and market capacity and energy prices assumed for the High and Low Fuel Cost
18 Scenarios. I note that other sensitivity runs performed by the Company, such as the High
19 and Low Construction Cost run, used a plus/minus 25 percent adjustment. Regardless of
20 the actual values assumed by the Company, as fuel prices increase, renewable energy

³³ See Exhibit 116, PUE-2011-00027 (chart showing RECs purchased from other generators during 2010).

1 sources become more cost-competitive with traditional fossil fuel supply, although this is
2 also occurring as a result of technology improvement and other public policies.

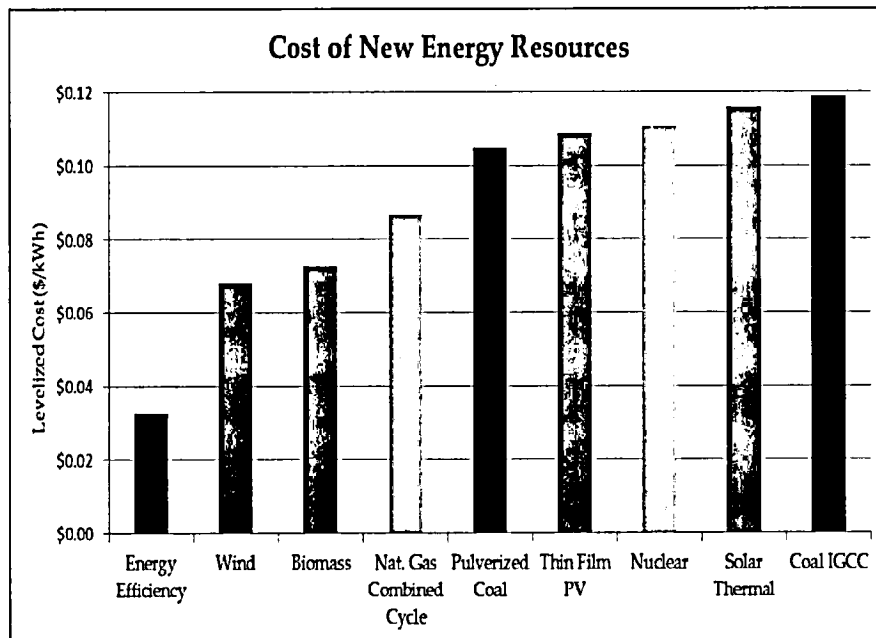
3 **Q. Please provide examples of increasing cost competitiveness of renewable energy**
4 **technologies.**

5 A. Renewable energy continues to expand in several areas of the country. Growth,
6 particularly in photovoltaic (PV) solar and wind, has largely been driven by renewable
7 portfolio standards, federal tax credits and the American Recovery and Reinvestment Act
8 of 2009 (“ARRA”). The U.S. EIA reports that renewable generated electricity is expected
9 to account for 17 percent of the nation’s total load in 2035, up from 9 percent in 2008.³⁴

10 Federal and state policies are designed, in essence, to de-carbonize the electric
11 grid and transform the renewable energy market so that renewable energy production
12 facilities can reach scale economies in a shorter period of time. In many respects, a state
13 RPS, if well designed, can also be an insurance policy to reduce a state’s exposure to
14 increasingly stringent federal environmental regulations. These policies are working. In
15 contrast to the Company’s assumptions, a potential study for Virginia, published by
16 ACEEE in 2008, estimated the levelized cost of wind and biomass to be less than the
17 marginal cost of natural gas combined cycle plants as shown in the table below.³⁵

³⁴ See http://www.eia.gov/energy_in_brief/renewable_energy.cfm (accessed 2/20/2012)

³⁵ See ACEEE, *Energizing Virginia: Efficiency First*, at 6 (Sept. 2008).



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According to ACEEE's 2008 report, energy efficiency is the least expensive resource in Virginia, followed by wind and biomass. PV resources are considered cost competitive with marginal nuclear power and less expensive than Coal IGCC. Since publication of the ACEEE report, some renewable energy costs have continued to decline. In comments to the Tennessee Valley Authority, the Southern Alliance for Clean Energy noted that cost of PV is estimated to decline by as much as 45 percent by 2030 as demonstrated in the table below:³⁶

³⁶ Comment of Southern Alliance for Clean Energy ("SACE") on TVA's 2010 Integrated Resource Plan, (filed Nov. 15, 2010).

1

| PV Technology | Installed costs (\$/kW _{DC}) | | |
|--|--|-------|-------|
| | 2010 | 2020 | 2030 |
| Ground-mounted Polycrystalline PV: with tracking (10 – 50 MW) | 5,900 | 4,900 | 3,750 |
| Ground-mounted Polycrystalline PV: w/o Tracking (10 – 50 MW) | 5,500 | 4,300 | 3,100 |
| Ground-mounted polycrystalline PV: w/o tracking (100 – 300 MW) | 4,800 | 3,800 | 3,100 |
| Ground-mounted Thin-film PV: w/o tracking (10 – 50 MW) | 4,800 | 3,800 | 3,100 |
| Ground-mounted Thin-film PV: w/o tracking (100 – 300 MW) | 4,700 | 3,700 | 3,000 |
| Roof-mounted Polycrystalline PV: commercial (10 kW – 2 MW) | 5,600 | 4,350 | 3,100 |
| Roof-mounted Polycrystalline PV: residential (1 kW – 10 kW) | 7,100 | 5,700 | 4,400 |

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In Michigan, a recently published report suggests that the cost of renewable energy is less than the cost of coal-fired generation.³⁷ According to the report from the Michigan Public Service Commission, renewable energy costs roughly \$91 per MWh compared to \$131 per MWh for coal. The study also indicates that Michigan’s renewable energy standard fosters \$5 billion in economic activity per year and supports more than 20,000 jobs.

9

10

11

Had the Company conducted a renewable energy potential study, it would have been able to more precisely inform the SCC and other stakeholders about the amount of energy that could displace coal-fired generation and the costs. It could have also reported

³⁷ Michigan Public Service Commission, *Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards*, February 15, 2012.

1 on the economic benefits and additional jobs that are generated by the renewable energy
2 sector in the state, which is relevant to the public interest analysis in a CPCN proceeding.

3 **Q. Please summarize your conclusions and recommendations.**

4 **A.** Based on my review of the IRP, I conclude that the IRP is deficient in many material
5 areas and does not reflect industry best practices for the reason highlighted above. In
6 short:

- 7 • The IRP is based on a load forecast that has not been fully explained and may
8 well be over-stated.
- 9 • The IRP does not consider renewable energy resources and energy efficiency
10 resources on an equal basis with supply side options within the Company's
11 planning models. As a result, customers will likely face higher costs from
12 construction of new generation and from expensive environmental compliance
13 costs for existing generation assets.
- 14 • At the same time, the Company does appear to acknowledge at least some of
15 the environmental compliance costs. As a result, the retirement decisions for
16 certain coal-fired generation units are well-justified.
- 17 • The IRP does not include higher energy savings rates from efficiency despite
18 the fact that energy efficiency is a low cost and low risk alternative to supply
19 side options. In fact, forecasted energy efficiency is far less than what could
20 reasonably be achieved and what many other organizations are achieving
21 today.

*Direct Testimony of Jeffery Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00092
March 15, 2012*

1 Due to these shortcomings, the SCC should direct the Company to convene a
2 stakeholder committee within 30 days of a Final Order and resubmit a new IRP within 12
3 months. To truly capture value from the stakeholder committee and demonstrate its
4 commitment to the stakeholders, the Company should be required to submit a consensus
5 IRP, if at all possible. If no consensus can be achieved, then the parties and stakeholders
6 would retain all of their rights before the Commission in future proceedings on the IRP.

7 **Q. Does this conclude your testimony?**

8 **A. Yes.**

Exhibit
ER-JML-1



**JEFFREY M. LOITER
MANAGING CONSULTANT**

Mr. Loiter has over 14 years of consulting experience in energy and natural resource issues. His energy experience includes policy, planning and program design, research on renewable and efficiency technologies, electricity transmission systems, integrated resource planning and savings verification. As a Managing Consultant, Mr. Loiter manages projects, oversees staff development, and contributes to firm management in the areas of hiring and business development.

PROFESSIONAL EXPERIENCE

Optimal Energy, Inc.

Bristol, VT

Managing Consultant, 2006-present

- Managing Optimal's participation in a team developing a Five-Year Energy Efficiency and Demand Response Plan for the Tennessee Valley Authority. Optimal's role focused on programs for the commercial sector in TVA's service territory, encompassing efforts to reach a variety of markets and end-uses, including specific offerings for both very large and small commercial entities.
- Supporting Efficiency Vermont Business Energy Services group with technical analysis, market research, and program design consultation. Recent projects include market characterization studies of refrigeration, lodging establishments, and food service entities; and developing several Technical Resource Manual entries.
- Supporting Massachusetts Energy Efficiency Advisory Council on program planning and implementation and technical analysis. Currently participating in the CHP Working Group, guiding program implementation strategies and analytical approaches.
- Supporting program implementation and on-going program design and development for Orange and Rockland Utilities. Previously managed the preparation of a DSM plan and Commission filings for this client. The project included on-site customer audits and residential surveys, efficiency program designs, and an efficiency potential study.
- Prepared comments and related materials on utility IRP filings in support of the Missouri Department of Natural Resources. Review focused on compliance with IRP regulations and critique of filed DSM plans as compared to best-practice.
- Led Optimal's participation in preparing a Technical Resource Manual for the Mid-Atlantic States (Maryland, Delaware, District of

Columbia), for the Northeast Energy Efficiency Partnerships' Regional EM&V Forum.

- Supported the Maryland Energy Administration in their review of utility energy efficiency plans and the design and implementation of state-delivered efficiency programs.
- Provided recommendations to improve a targeted DSM program being delivered under contract to a major northeast electric utility. Interviewed program staff and provided recommendations based on best practice approaches for similar target markets.
- Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.
- Conducted potential analysis for a Canadian Atlantic province, including commercial and institutional sector program design and overall analytical oversight.
- Developed residential potential analysis for the non-transmission alternative to a proposed transmission line upgrade in Vermont.
- Prepared report on efficiency potential in Texas in support of discussions related to proposed expansion of coal-fired generating capacity, for two major NGOs.

Independent Consultant

Cambridge, MA

2005-2006

- For the Massachusetts Renewable Energy Trust SEED Initiative, evaluated renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards recommended for approval totaled \$1.4 million.
- Led an effort to draft a whitepaper on policies to encourage investment in electricity transmission facilities.
- Prepared two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in Petroleum Technology Quarterly (1Q 2006) and BCC Research/Energy Magazine (2006).

Industrial Economics, Incorporated

Cambridge, MA

Associate, 1997-2000; Senior Associate, 2001-2004

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Incorporated

New Orleans & Boston

1991-1995

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

EDUCATION

M.S., Technology & Policy, Massachusetts Institute of Technology, Cambridge, MA, 1997

B.S. with distinction, Civil and Environmental Engineering, Cornell University, Ithaca, NY, 1991

PUBLICATIONS

"From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers," (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings*, Pacific Grove, CA, August 2008.

National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies*. Prepared by Philip Mosenthal and Jeff Loiter, Optimal Energy, Inc. December.

Loiter J.M and V. Norberg-Bohm (1999), "Technology policy and renewable energy: public roles in the development of new technologies," *Energy Policy* Vol.27 no.85-97

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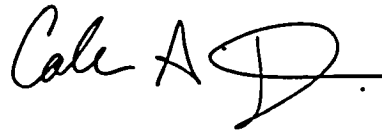
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DATED: March 15, 2012

A handwritten signature in black ink, appearing to read "Cale A. Jaffe". The signature is fluid and cursive, with a horizontal line extending from the end of the name.

Cale Jaffe
Southern Environmental Law Center

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COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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APPLICATION OF CASE NO. PUE-2011-00093
VIRGINIA ELECTRIC AND POWER COMPANY

 ORIGINAL

For approval to implement new demand-side
management programs and for approval of
two updated rate adjustment clauses pursuant
to § 56-585.1 A 5 of the Code of Virginia

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SCC Hearing PUE-2011-00093
Richmond, Virginia
Wednesday, March 7, 2012
9:30 a.m.

Reported by: Cassandra E. Ellis, RPR

Volume II

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COMMONWEALTH OF VIRGINIA
State Corporation Commission

APPLICATION OF CASE NO. PUE-2011-00093
VIRGINIA ELECTRIC AND POWER COMPANY
For approval to implement new demand-side
Management programs and for approval of
two updated rate adjustment clauses pursuant
to § 56-585.1 A 5 of the Code of Virginia

The complete transcript of the testimony
and other incidents of the above-captioned matter when
heard on March 7, 2012, before the Honorable
Commissioners of the State Corporation Commission,
Richmond, Virginia.

Reported and transcribed
By: Cassandra E. Ellis, RPR

130410134

1 Honorable James C. Dimitri, Member Presiding

2 Honorable Judith Williams Jagdmann, Member

3 Honorable Mark C. Christie, Chairman

4

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| 2 | (Retained by the Commission) | | |
| 3 | Hearing Exhibit | | |
| 4 | Exhibit 11 Public Version of David L. | 305 | 307 |
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| 1 | E X H I B I T S C O N T I N U E D | | |
| 2 | (Retained by the Commission) | | |
| 3 | Hearing Exhibit | | |
| 4 | Exhibit 16C Confidential Version of Company's | 315 | 332 |
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| E X H I B I T S C O N T I N U E D | | | |
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| 1 | E X H I B I T S C O N T I N U E D | | |
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E X H I B I T S C O N T I N U E D

(Retained by the Commission)

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| Dominion | | |

20410134

1 P R O C E E D I N G S

2 COMMISSIONER DIMITRI: Good morning.

3 Ms. Link?

4 MS. LINK: Thank you, Your Honor. We,
5 overnight, have been able to stipulate -- work out
6 stipulations for -- for the direct testimony of the
7 final Company witnesses on direct.

8 So at this time if we could mark those and
9 I can identify them for you individually and we can
10 mark them as -- as exhibits.

11 COMMISSIONER DIMITRI: All right.

12 MS. LINK: The first would be the direct
13 testimony of David L. Turner, and that is ten typed
14 pages of questions and answers, an Appendix A, an
15 exhibit consisting of three schedules, and they were
16 filed in public and extraordinarily sensitive
17 versions, and they were revised, one page was revised
18 on February 16th, 2012, and we have those -- that
19 testimony and schedules and exhibits marked in public
20 and extraordinarily sensitive versions.

21 COMMISSIONER DIMITRI: All right.

22 Mr. Turner's direct testimony, with revisions, will be
23 marked as Exhibit 11 and the confidential version will
24 be marked as 11C.

25 (Exhibit No's. 11 and 11C were marked for

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1 identification.)

2 MS. LINK: Thank you.

3 Next is the direct testimony of Rick L.
4 Propst, it consists of a -- of 13 typed pages of
5 questions and answers, an Appendix A, as an exhibit
6 consisting of one schedule, it is in public and
7 extraordinarily sensitive versions, with no
8 corrections. May we have that marked?

9 COMMISSIONER DIMITRI: Mr. Propst's direct
10 testimony will be Exhibit 12 and confidential version
11 will be 12C.

12 (Exhibit No's. 12 and 12C were marked for
13 identification.)

14 MS. LINK: Thank you. Next we have the
15 direct testimony of Paul B. Haynes, it consists of a
16 document of 16 typed pages of questions and answers,
17 an Appendix A, an exhibit consisting of three
18 schedules, it was filed in public and extraordinarily
19 sensitive versions. There -- there was an error but
20 it -- it was corrected in his rebuttal testimony, so
21 at this time may we have the public and
22 extraordinarily sensitive versions marked?

23 COMMISSIONER DMITRI: Yes, Mr. Haynes'
24 direct testimony, public version, will be marked as
25 Exhibit 13, confidential version will be marked as

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1 Exhibit 13C.

2 (Exhibit No's. 13 and 13C were marked for
3 identification.)

4 MS. LINK: Thank you. And finally we have
5 the direct testimony of Kurt W. Swanson consisting of
6 11 typed pages of questions and answers, an Appendix
7 A, as an exhibit consisting of seven schedules, it is
8 in public version, only. May we have that marked?

9 COMMISSIONER DMITRI: Yes, Mr. Swanson's
10 direct testimony will be marked as Exhibit 14.

11 (Exhibit No. 14 was marked for
12 identification.)

13 MS. LINK: At this time it -- move the
14 admission of Exhibit 11, 11C, 12, 12C, 13, 13C, and 14
15 into the record.

16 COMMISSIONER DIMITRI: They will be so
17 admitted.

18 (Exhibit No's. 11, 11C, 12, 12C, 13, 13C,
19 and 14 are received into evidence.)

20 MS. LINK: Thank you.

21 COMMISSIONER CHRISTIE: Yeah, I had a que-
22 -- I had a question, Ms. Link, for Mr. Propst?

23 MS. LINK: Oh, yes, he's here.

24 COMMISSIONER CHRISTIE: Or anybody else to
25 answer. It's -- okay, may we just put him up here?

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1 MS. LINK: Absolutely, the Company calls
2 Rick Propst.

3 COMMISSIONER CHRISTIE: Is it Props or
4 Propst?

5 MS. LINK: Propst.

6 COMMISSIONER CHRISTIE: Okay, I had a
7 friend in high school and it was the same spelling and
8 it was Props.

9 RICK L. PROPST
10 having been first duly sworn, testified as follows:

11 COMMISSIONER CHRISTIE: Okay, this won't
12 take long, I just have one question about your
13 schedule one, if you just want to move, schedule one,
14 page two, if you want to just go ahead and open that
15 up?

16 THE WITNESS: Okay, I'm there.

17 COMMISSIONER CHRISTIE: On the electric
18 vehicle program, which is down near the bottom of the
19 first green bar?

20 THE WITNESS: Yes.

21 COMMISSIONER CHRISTIE: And you show a
22 total rate year of 570,000, roughly?

23 THE WITNESS: Yes.

24 COMMISSIONER CHRISTIE: And I just wanted
25 to confirm that that was within -- the order, when we

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1 approved the electric vehicle file is -- set a cap of
2 825,000, with no lost revenue, and I just want to
3 confirm that 570, obviously it's below 125, but that
4 -- so you haven't -- you haven't reached the 825 cap
5 yet, then; right?

6 THE WITNESS: That's correct.

7 COMMISSIONER CHRISTIE: Okay. So that 570
8 is not an -- an increment over some other amount that
9 you've already spent?

10 THE WITNESS: That -- that's correct. It's
11 a -- it would be a part of the 850.

12 COMMISSIONER CHRISTIE: The 850?

13 THE WITNESS: Yes.

14 COMMISSIONER CHRISTIE: And that does not
15 include a lost revenue?

16 THE WITNESS: That's correct.

17 COMMISSIONER CHRISTIE: Okay, that's all I
18 have.

19 MS. LINK: Thank you. With that, the
20 Company has presented -- completes its direct case.

21 COMMISSIONER DIMITRI: All right.

22 Mr. Jaffe?

23 MR. JAFFE: Thank you, Your Honors.

24 Environmental respondents call Jeff Loiter, and while
25 Mr. Loiter's making his way up, just a procedural

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1 question. We have some extraordinarily sensitive
2 additions to his testimony, and just a couple of
3 extraordinarily sensitive sur rebuttal questions, the
4 lion's share of the sur rebuttal is public, so I've
5 talked with other counsel, what I would propose, and
6 obviously it's up to, you know, the Commission's
7 discretion, that we do his confidential or
8 extraordinarily sensitive additions and brief sur
9 rebuttal, then have cross on that, to the extent there
10 is cross, then go back to -- to public to complete his
11 sur rebuttal, but it's obviously however you'd prefer
12 to -- the Court would prefer to do it.

13 COMMISSIONER DIMITRI: I -- I -- I think
14 that'll work. We'll do that.

15 And Mr. Jaffe, when -- when you get to that
16 point in -- you're going to have to -- you're going to
17 have to let us know and -- and we will have to ask
18 anyone who has not signed the confidentiality
19 agreement to leave the courtroom, and we'll also have
20 to go off the web.

21 MR. JAFFE: Absolutely, Your Honor.

22 COMMISSIONER DIMITRI: And are -- are you
23 going to start with --

24 MR. JAFFE: I'll -- I just have the -- this
25 through the preliminary questions.

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1 COMMISSIONER DIMITRI: All right.

2 MR. JAFFE: And then we'll get to the rest
3 in probably five questions from now or less.

4 COMMISSIONER DIMITRI: All right.

5 JEFFREY LOITER

6 having been first duly sworn, testified as follows:

7 DIRECT EXAMINATION

8 BY MR. JAFFE:

9 Q Will you please state your name, address,
10 and employer -- employer?

11 A Yes. My name is Jeffrey Loiter, I work for
12 Optimal Energy, Incorporated, we're located in
13 Bristol, Vermont, at 14 School Street.

14 Q And you are here as a witness on behalf of
15 the environmental respondents; is that correct?

16 A Yes.

17 Q Can you briefly just state your expertise
18 specifically as it relates to utility sponsored energy
19 efficiency programs and DSM cost effectiveness tests?

20 A Yes. For the past five and a half years I
21 have been working on a variety of energy efficiency
22 programs sponsored by utilities and third-party
23 delivery administrators. This work has included
24 developing program designs, estimating savings from --
25 for measures and from programs, conducting cost

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1 effectiveness tests, performing potential studies for
2 a variety of programs and portfolios, for, again, for
3 utilities sponsored and third-party administered
4 efficiency programs and DSM programs.

5 Q And did you cause to be filed in this
6 docket, on January 17th, 2012, on behalf of the
7 environmental respondents, 29 pages of public
8 testimony and one exhibit?

9 A Yes.

10 MR. JAFFE: Your Honors, if there is no
11 objection, I'd have the public version of Mr. Loiter's
12 testimony marked and move its admission as an exhibit.

13 COMMISSIONER DIMITRI: All right.
14 Mr. Loiter's direct testimony will be marked as
15 Exhibit 15 and admitted subject to cross-examination.

16 (Exhibit No. 15 was marked for
17 identification and received into evidence.)

18 MR. JAFFE: All right. And at this point
19 I'd like to now ask Mr. Loiter about his
20 extraordinarily sensitive or confidential additions to
21 that testimony.

22 COMMISSIONER DIMITRI: All right. At -- at
23 this juncture, then, we will ask any -- anyone who has
24 not signed the confidentiality agreement in this
25 matter to please leave the courtroom. You will be

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1 notified when the confidential session is over and at
2 that time you may return. I'll ask the bailiff to
3 turn off our webcast for that period, as well.

4 All right, and if I could ask that the --
5 the door to be closed, as well.

6 (Whereupon, the proceedings continued as
7 confidential.)

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1 (Confidential portions of Mr. Jeffrey
2 Loiter's testimony can be found under separate binder
3 and run from page 314 to page 361.)
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1 (Whereupon, the proceedings continued as
2 public.)

3 COMMISSIONER DIMITRI: All right. Let's
4 open the courtroom, Sherman, if you will put us back
5 on the web. We're now back in public session.

6 Mr. Jaffe?

7 MR. JAFFE: Thank you, Your Honor. First,
8 I'd like to -- to pass out and move the admission of
9 document 16, public, which is a -- Company's response
10 to environmental respondents, interrogatories set one,
11 question 15; Exhibit 17, Company's response to staff
12 interrogatory sixth set, question 47; Exhibit 18,
13 Company's response to staff interrogatories fifth set,
14 question 44; Exhibit -- and Exhibit 19, Company's
15 response to staff's interrogatories fifth set,
16 question 43, all redacted versions of those
17 interrogatory responses.

18 COMMISSIONER DIMITRI: Those exhibits will
19 be admitted subject to any cross-examination.

20 (Exhibit No's. 16, 17, 18 and 19 were
21 marked for identification and received into evidence.)

22 CONTINUED DIRECT EXAMINATION

23 BY MR. JAFFE:

24 Q Now, Mr. Loiter, you explained that you now
25 fully -- that any conditions that you had in terms of

1 qualifications on your support for the -- the five
2 efficiency programs, that we've discussed at length,
3 those concerns have been, to the extent there were any
4 concerns, have been resolved; is that correct?

5 A That's correct.

6 Q And can you state your position now with --
7 also with regard to the commercial distributed
8 generation program, now, after having, of course,
9 reviewed all the extraordinarily sensitive material
10 and had access to it?

11 A My recommendation with respect to that
12 program has -- has not changed, either, as a result of
13 the -- any of the additional extraordinarily sensitive
14 information.

15 And as I state in my testimony, we -- I
16 don't feel that that is an appropriate program to be
17 considered as an efficiency program. And -- and I
18 can't recommend approval of that as an efficiency
19 program.

20 Q All right. Let me move now to discussion
21 of the cost effectiveness tests that are at issue in
22 this case.

23 Yesterday during proceedings Mr. Newcomb
24 and Judge Christie discussed, at length, the TRC and
25 RIM tests, and the issue of why lost revenues are

1 factored into the RIM test but not into the TRC or
2 other tests.

3 Can you address this, ex- -- explaining why
4 lost revenues are -- are not factored into the -- to
5 all the tests and whether that should be of concern to
6 rate payers?

7 A Yes. I think the primary thing to
8 understand about lost revenues is that they do not
9 represent an additional cost of undertaking DSM
10 programs.

11 In -- the cost effectiveness tests are --
12 their intent is to measure the result of a change in
13 behavior. The no action case is the Company continues
14 to deliver energy in the same manner that they have,
15 and the case we're assessing is investing in
16 efficiency programs and causing there to be less
17 energy consumed.

18 And under the former, the Company is
19 recovering an amount of revenues determined in -- in
20 -- in -- in this room, what -- you know, based on --
21 on rate cases and -- and the cost of their doing
22 business, and under the case where they use
23 demand-side management to meet part of their load, and
24 when the Commission agrees to provide them with the
25 lost revenues that they would otherwise have

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1 collected, those lost revenues are designed to exactly
2 keep that collection the same.

3 There is no increase in revenue collection
4 under the DSM case. Those lost revenues are not an
5 addition. They're not monies that would not have been
6 collected under the no action case.

7 The reason they're included in the -- the
8 RIM test is because they give an indication as to the
9 rate at which the Company needs to recover their costs
10 on a per kilowatt hour basis.

11 And that's why I -- I think the RIM test
12 should most appropriately be called the rate impact
13 measure test rather than the rate payer impact measure
14 test. It measures the effect on the per kilowatt hour
15 rate, only, it does not measure -- the RIM test does
16 not measure the effect on total rate payer costs.

17 I don't think it's appropriate to consider
18 lost revenue as an additional cost of pursuing DSM
19 programs.

20 COMMISSIONER CHRISTIE: Well, let me ask
21 you, rate payers are paying the cost, right?

22 THE WITNESS: Yes. Yes.

23 COMMISSIONER CHRISTIE: It's in their
24 rates?

25 THE WITNESS: That's correct.

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1 COMMISSIONER CHRISTIE: Now, I understand
2 in the RIM test, which does account for that
3 specifically as a cost, if you are, you know, and --
4 and we -- you know, if you're above one, even -- even
5 with that cost both participants and non-participants
6 come out okay, below one non-participants lose,
7 participants maybe continue to win, but in TRC, where
8 it's not factored in --

9 THE WITNESS: Mm-hmm.

10 COMMISSIONER CHRISTIE: -- it's still a
11 cost to rate payers?

12 I mean, there's no question you're putting
13 lost revenues and number, in this case Dominion's
14 asking for 25 million dollars, and Mr. Jaffe's next
15 witness is going to go into, you know, how that should
16 be verified --

17 THE WITNESS: Mm-hmm.

18 COMMISSIONER CHRISTIE: -- and -- and that
19 sort of thing. And, you know, you can take that 25
20 million dollars over, you know, a five-year period of
21 this program, maybe 125 million dollars, depending if
22 it doesn't get cutoff in the final review, and
23 Mr. Powell addresses that, you can take 25 years over
24 the whole study period.

25 THE WITNESS: Mm-hmm.

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1 COMMISSIONER CHRISTIE: 1.4 billion, I
2 mean, depending on how far you want to take it. But
3 it is a cost, it goes into rates, it is not
4 speculative, unlike a lot of things, you said -- you
5 made an interesting comment, you said all these
6 forecasts about gas are just, you know, they're always
7 usually wrong.

8 The lost revenue part that goes to rate
9 payers is probably the only thing is this proceeding
10 that is not speculative because it is a real cost
11 that's going to go into rates; correct?

12 THE WITNESS: I don't think that's correct,
13 because I think that that leaves out the statement
14 that that was money that the rate payers were going to
15 pay anyway.

16 COMMISSIONER CHRISTIE: Well, let me ask
17 you -- okay.

18 THE WITNESS: It's not an additional cost.

19 COMMISSIONER CHRISTIE: Well, if it's a
20 participant, now, in the TRC we're talking
21 participant, okay?

22 THE WITNESS: TRC co- -- covers all -- all
23 --

24 COMMISSIONER CHRISTIE: Participant costs?

25 THE WITNESS: All -- no, all rate payers.

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1 COMMISSIONER CHRISTIE: I thought TRC was
2 utility cost plus participant?

3 THE WITNESS: Usually it's called the --

4 COMMISSIONER CHRISTIE: Well, let's --

5 THE WITNESS: -- the total resource cost,
6 it's des- -- designed to look at the --

7 COMMISSIONER CHRISTIE: Well, then, let me
8 say -- let's say it's all customers, then.

9 THE WITNESS: The economy as a whole.

10 COMMISSIONER CHRISTIE: I thought it was
11 participant, but it -- I thought it was utility cost
12 plus participant cost, but let's -- if it's -- if it's
13 all rate payers then if -- if you're saying that it's
14 -- the reason lost revenues shouldn't be counted as
15 cost is because it's supposed to be a wash that, you
16 know, the -- the customer saves by not using the
17 electricity, and what the customer is saving is what
18 the Utility is losing in the revenue, right? So
19 that's supposed to be the wash, is that what -- is
20 that what you're saying?

21 THE WITNESS: No, sir, it's not. I'm
22 sorry.

23 COMMISSIONER CHRISTIE: Okay.

24 THE WITNESS: It -- the -- the reason to do
25 these economic tests --

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1 COMMISSIONER CHRISTIE: Mm-hmm.

2 THE WITNESS: -- is to assess the change
3 from the current condition to some proposed condition.
4 If you are going to compensate the Utility for the
5 revenue that they don't collect or that they would
6 have collected in the -- the no action, and you're
7 going to have them collect the same amount of revenue
8 in the with action, with DSM, there's been no change
9 in that revenue collection to rate payers.

10 The only thing that's changed when we do a
11 -- a -- a DSM po- -- well, two things have changed by
12 -- by -- by engaging in the efficiency, the total cost
13 of supplying the energy to Dominion's entire customer
14 base is less, and they have also sold less energy.

15 I -- if I could make an analogy, if the --
16 the -- if we have a mild year of weather and the
17 Company sells fewer KWH --

18 COMMISSIONER CHRISTIE: Mm-hmm.

19 THE WITNESS: -- because customers use less
20 energy, then they would -- and if that happened a
21 couple years in a row, then they would come before the
22 Commission and say, you know what, we've sold a lot
23 fewer KWH than we thought we were going to, and so
24 we're not recovering the costs at the rate we need to,
25 we need to make an adjustment and our rates would --

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1 would go up, that would, you know, indicate a -- a --
2 a rate impact, you know, a score of less than -- than
3 one, but you wouldn't say that --

4 COMMISSIONER CHRISTIE: Well, customers
5 wouldn't be charged for the lost revenue, though, I
6 mean, if the weather is mild --

7 THE WITNESS: Well, they would, you're --
8 they -- they -- they -- the Company --

9 COMMISSIONER CHRISTIE: Right, that's what
10 I said.

11 THE WITNESS: -- said, I didn't get that
12 revenue, and so I need you now to give me that revenue
13 by increasing rates, and you wouldn't deny the Company
14 that revenue in increased rates, and you wouldn't also
15 say that the customer is worse off because the weather
16 was mild and they didn't have to use as much
17 electricity.

18 COMMISSIONER JAGDMANN: That would be
19 prospective, wouldn't it, the change in rates would be
20 prospective, you wou- -- you wouldn't go backward in
21 time and collect the lost revenue?

22 THE WITNESS: When it -- I mean, it's my --
23 I mean, I'm not a -- a rate making expert, but my
24 understanding is that if due to whatever factors
25 Utility under recovers substantially through --

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1 through no fault of their own, because the economy,
2 for example, goes down and they -- they sell a lot
3 fewer KWH, and therefore, they're not recovering all
4 their fixed costs that they have to, you know, that
5 they've -- all the things that they've invested in
6 that you're -- when you'd set the rates the next time
7 that that would be incorporated and -- and -- and
8 Trued-Up, that's my understanding of the way the rates
9 are --

10 COMMISSIONER CHRISTIE: So it's
11 prospective.

12 THE WITNESS: I'm sorry?

13 COMMISSIONER CHRISTIE: It would be
14 prospective?

15 THE WITNESS: So you would completely
16 ignore -- they -- they would just be --

17 COMMISSIONER JAGDMANN: Out.

18 THE WITNESS: They would be out the money,
19 regardless.

20 COMMISSIONER CHRISTIE: It's called
21 opportunity to earn, not guaranteed earning.

22 THE WITNESS: Okay. It -- it -- it -- I --
23 I -- my understanding is that in -- at least in some
24 places that that -- that when you have these periodic
25 rate cases it correlates the effect of whether or not

1 that that -- that came true or not, each through --
2 you know, again, through no fault of their own,
3 weather adjustments or whatever. I -- I -- I could be
4 wrong. Again, I'm not a rate making expert.

5 Re- -- regardless of that, I think the --
6 the -- the key thing I want to convey, that I hope I'm
7 trying to convey clearly, is that by its very nature
8 you're -- you're providing the Utility with the same
9 revenue in either case, and that the DSM case does not
10 mean the rate payers are paying more to the Utility
11 than they were before, and, in fact, they're paying --
12 they're paying less, overall, custom- -- the -- the
13 Utility's customers are paying less for energy, over
14 all the customers.

15 You -- you did point out the one thing that
16 the RIM test does do, and that it does indicate that
17 there's a shift in distribution of cost between
18 participants and non-participants, that's absolutely
19 true, that's a valid concern and issue for the
20 Commission to consider in looking at efficiency
21 programs, is that there is a distributional effect of
22 them.

23 I would encourage the Commission, in
24 considering that distributional effect, to consider
25 the relative scale of that distributional effect

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1 compared to the, you know, the overall, you know, body
2 of -- of, you know, payments and -- and revenues that
3 -- that the rate payers have to support.

4 I think I called it out of my testimony the
5 relatively small amount of additional monthly bill for
6 some customers, and the relatively minor changes that
7 would be necessary to -- to offset that, such that
8 anybody can become a participant relatively, you know,
9 straight, you know, in a relatively straight forward
10 manner to at least come out even.

11 The fact is when you look at the other
12 three tests it's clear that there are very substantial
13 economic benefits to the rate payers, overall, on the
14 tune of hundreds of millions of dollars from the
15 post-DSM programs.

16 BY MR. JAFFE:

17 Q Mis- -- Mr. Loiter, just go back on this
18 lost revenues point?

19 A Sure.

20 Q Is the -- the point that when the DSM
21 programs are implemented, compared to the no action
22 alternative, that items, you know, variable costs like
23 fuel costs, for example, those are saved?

24 A That's correct.

25 Q And those savings accrued to the customers;

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1 correct?

2 A That's right, the -- the -- the -- the
3 things that can be avoided are avoided, and that's the
4 basis for the benefit calculation for -- for all of
5 these tests, it's -- it's -- it's the cost -- it's
6 what's not needed, it's what's not consumed, from the
7 Utility perspective or the total resource perspective
8 it's the -- sort of the -- the market price of energy,
9 from the participant perspective it's the retail price
10 of energy, but -- but either way, it's -- that's the
11 benefit. And the cost is what it costs to actually
12 make those happen.

13 And -- and my contention is that the lost
14 revenue is the same in -- in -- in either case. The
15 revenue is going to go to the Utility in either case.

16 COMMISSIONER DIMITRI: Well, that assumes,
17 doesn't it, theoretically, that the Utility is
18 recovering right at the revenues that it -- it needs,
19 and that the program that creates a lost revenue --

20 THE WITNESS: Mm-hmm.

21 COMMISSIONER DIMITRI: -- will somehow
22 cause the Utility to earn less than is necessary to
23 earn its authorized return on -- on its investments;
24 correct?

25 THE WITNESS: Yes. I --

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1 COMMISSIONER DIMITRI: So to the extent
2 that that's only theoretical and -- and not the case
3 in reality, there wouldn't be this wash that you're
4 talking about, the lost revenues would require
5 additional dollars from rate payers, wouldn't it?

6 THE WITNESS: I'm -- I'm sorry, I didn't
7 understand the -- the distinction between the
8 theoretical, the hypothetical, and the -- in your
9 statement. I'm sorry.

10 COMMISSIONER DIMITRI: Let's assume that --
11 that the Utility is already recovering its revenu- --
12 it -- the revenues needed.

13 THE WITNESS: Okay.

14 COMMISSIONER DIMITRI: And something in
15 addition to that?

16 THE WITNESS: Right.

17 COMMISSIONER DIMITRI: Okay?

18 THE WITNESS: Okay.

19 COMMISSIONER DIMITRI: You then award lost
20 revenues because of a program that you're
21 implementing? Your theory is that, well, that would
22 be a wash because the Utility would not be able to
23 cover its -- its expenses, otherwise, so they've got
24 to be compensated for that.

25 THE WITNESS: I -- I feel like there's a

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1 timing issue that I'm not exactly understanding.
2 You're saying that at a particular point in time the
3 Utility has been recovering its revenue appropriately,
4 and now we implement, going forward, a -- a DSM
5 program which will cause them to under recover?

6 COMMISSIONER DIMITRI: No, let's say they
7 don't under recover.

8 THE WITNESS: I don't see that as -- I
9 don't understand that construction, then, I'm sorry.
10 If -- if they deliver a program, sell fewer kilowatt
11 hours, assuming, you know, everything else and all the
12 rate making was done correctly, they're going to
13 recover less than they need because they can't
14 avoid -- part of what they recover in revenues is not
15 avoidable by selling fewer kilowatt hours because of
16 efficient lighting or something like that, there's all
17 those other costs that -- that -- that are not
18 variable, that -- that are part of rates.

19 And so to the extent that an efficiency
20 program reduces their sales, I -- I don't believe that
21 they will recover the revenues that they would have
22 otherwise recovered.

23 COMMISSIONER DIMITRI: Right, which may be
24 different from the revenues necessary to provide full
25 return on their investments, depends on the rate

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1 making mechanism, doesn't it?

2 THE WITNESS: It de- -- it depends on the
3 rate making mechanism, it depends on what you decide
4 about their lost revenue recovery. Ideally the lost
5 -- the riders that are proposed and that not part of,
6 you know, my -- my purview of -- in my review, but
7 ideally those are designed to recover only those
8 revenues that are necessary to -- to compensate for
9 that, for that difference.

10 COMMISSIONER DIMITRI: Okay.

11 THE WITNESS: That's -- that's my
12 understanding, that's -- that's ideally how they're
13 constructed.

14 COMMISSIONER CHRISTIE: Let me just ask you
15 one -- I'm sorry.

16 COMMISSIONER JAGDMANN: If -- if we're
17 compare -- if we're trying to compare the cost, let's
18 say of a unit of electricity that a utility is
19 currently generating --

20 THE WITNESS: Mm-hmm.

21 COMMISSIONER JAGDMANN: -- by traditional
22 means versus the demand-side management program, under
23 the traditional methodologies you'd have the cost of
24 production, whatever, and a profit or return that the
25 Utility allows, let's just take those two components,

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1 if we're comparing it to a DSM program we'd have the
2 price of production and a profit --

3 THE WITNESS: Okay.

4 COMMISSIONER JAGDMANN: -- on return? Now,
5 what I hear you saying is because you're already --
6 you've already calculated the profit in the price of
7 production you shouldn't look at it again on the
8 demand-side management, when you're evaluating the
9 demand-side management cost. You're say it's already
10 included. You -- you -- is that what you're saying,
11 you shouldn't look at it or shouldn't consider it?

12 THE WITNESS: I -- I wasn't making a dec-
13 -- an argument related to -- to the margin or their --
14 their -- their rate of return. Certainly part of the
15 lost revenue goes to support a return. But part of
16 any revenue requirement goes to support, you know, a
17 -- a variety of all the other costs that the Utility
18 has.

19 COMMISSIONER JAGDMANN: So you're making
20 the point that it's -- it's broader than that, it's --
21 it's a lost return?

22 THE WITNESS: Again, I think it's more than
23 just the return on the investment. They -- they've
24 lost -- they've lost the --

25 COMMISSIONER JAGDMANN: Revenue, you're --

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1 so it's broader, it's lost revenue?

2 THE WITNESS: It's lost revenue to recover
3 just the -- the costs, regardless, whether they had
4 any return on the -- on -- on their activity, in their
5 capital. Again, they're -- if -- if -- if the
6 Commission -- if the Company's rider proposals and the
7 Commission's findings on them and lost revenue are,
8 you know, accurate, correct, appropriately done, the
9 Utility has not recovered anymore revenue from rate
10 payers than it -- than it would have in the absence of
11 the DSM program, that's exactly how you're supposed to
12 try and calculate the lost revenue, it's what would we
13 have gotten had we not done this, and so that's not --
14 you haven't created more costs for the rate payer that
15 -- that didn't exist if you didn't do the DSM, but you
16 have saved them a lot of money.

17 COMMISSIONER CHRISTIE: Which gets into the
18 question of back to the TRC, if -- if in -- these are
19 all cost benefit tests, and you -- you had -- a few
20 minutes ago you said these are about changing
21 behavior, and that may be but --

22 THE WITNESS: Changing conditions.

23 COMMISSIONER CHRISTIE: Changing
24 conditions?

25 THE WITNESS: Yes.

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1 COMMISSIONER CHRISTIE: But every one of
2 these tests is -- is -- is about measuring costs and
3 benefits, right, I mean coming out with a number that
4 --

5 THE WITNESS: Mm-hmm.

6 COMMISSIONER CHRISTIE: -- everybody looks
7 at and says --

8 THE WITNESS: Yeah.

9 COMMISSIONER CHRISTIE: -- it's either good
10 enough or not good enough?

11 And in TRC, the savings from, you know,
12 energy that wasn't bought because of the DSM program
13 or capacity that wasn't built because of the DSM
14 program.

15 THE WITNESS: Yes.

16 COMMISSIONER CHRISTIE: And -- and
17 intuitively that should -- there should be some of
18 that, but that is supposed to be captured in that
19 numerator of the TRC test, right, if you -- if this is
20 accurately forecast, that's there?

21 THE WITNESS: Yes.

22 COMMISSIONER CHRISTIE: So the cost side of
23 it is, you know, balancing the costs against those
24 benefits, and I think I just heard you say with the
25 TRC, it -- the lost revenue should wash out because

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1 what the customer didn't -- didn't spend is what the
2 Utility didn't get, and so that should be a -- you
3 don't factor that in because it is a wash; correct?

4 THE WITNESS: That's -- I -- I -- I
5 understand your point, that's not the way I think of
6 it, because the TRC is not looked at from the
7 customer's spending perspective, it's looked at from
8 the -- sort of the -- the -- the global economic
9 perspective, which is why, for example, incentives
10 don't enter into -- in -- they don't enter into the
11 TRC because those are sort of transfer payments.

12 And so it's not in the denominator of the
13 TRC as a cost, again, because it's not a cost, there's
14 not been a change, it -- you can't point to something
15 that was spent that would not have been spent
16 otherwise.

17 The reason it's in the rate impact test as
18 a cost is because that test is only looking at the
19 effect on rates, and we're going to get into this
20 later, but you know, Mr. Norwood, you know, makes sort
21 of a -- a blanket statement that says there'll be no
22 customer benefits from -- from the proposed programs,
23 and I -- I believe he's making that statement because
24 the rate impact test is less than one, and so
25 therefore the benefits are less than the costs.

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1 The rate impact test does not look at the
2 total picture of all customers, the entire utility,
3 costs and benefits, it's a -- it's a special case
4 looking at one particular thing, what happens to
5 rates.

6 COMMISSIONER CHRISTIE: But the numerator's
7 the same, isn't it, even under RIM?

8 THE WITNESS: The numerator --

9 COMMISSIONER CHRISTIE: It's the avoided
10 capacity and the avoided -- and the avoided energy
11 cost? I mean, it's -- it uses the same numerator,
12 doesn't it, as TRC?

13 THE WITNESS: The numerator for the RIM
14 test and the numerator for TRC, I --

15 COMMISSIONER CHRISTIE: They -- they both
16 look at --

17 THE WITNESS: I think they -- I think they
18 both -- yes.

19 COMMISSIONER CHRISTIE: They both take
20 avoided capacity benefit and avoided energy benefit?

21 THE WITNESS: Mm-hmm.

22 COMMISSIONER CHRISTIE: And they both use
23 it as the numerator of this ratio?

24 THE WITNESS: That's correct.

25 COMMISSIONER CHRISTIE: There's no

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1 difference?

2 THE WITNESS: That's right.

3 COMMISSIONER CHRISTIE: So doesn't --
4 doesn't RIM test try to capture the benefits just as
5 much as TRC tries to capture benefits?

6 THE WITNESS: It -- it does capture -- try
7 to capture the benefits. I think this -- where the
8 problem comes in is that what's missing from the RIM
9 test in the numerator is the found revenue, you know,
10 if you want to look at, if you want to use the RIM.
11 test and say, well, here's the effect on a -- on the
12 individual or individuals in the -- in the system,
13 you're saying, well, I'm -- one of the costs I'm
14 seeing is, well, they have to pay this lost revenue.

15 But what you didn't include in the
16 numerator is all the found revenue that they didn't
17 spend, which is the difference between the retail rate
18 of electricity and those avoided costs, which are
19 less. And so that's not in there. And -- and --

20 COMMISSIONER CHRISTIE: It's the same as
21 the TRC. I mean, it's the exact same numerator as the
22 TRC?

23 THE WITNESS: It -- it is, and that's what
24 I'm saying is sort of flawed about the RIM test is by
25 -- by sort of looking at the RIM test and saying,

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1 well, customers are going to have to spend this lost
2 revenue, if you're going to say that -- that that's
3 the basis for -- for the way you measure it, is that
4 the customer is spending sort of on revenue which is
5 sort of based on a retail rate, then you also need to
6 include in the numerator the fact that a bunch of
7 people are not spending the retail rate for the energy
8 that they didn't consume, and the difference between
9 that retail rate.

10 And the avoided costs for the energy that
11 wasn't sold is sort of exactly how you calculate that
12 lost revenue of the Company because the Company has
13 not collected the retail rate.

14 But they've saved some energy as to the
15 avoided costs, and so you're going to give them the
16 difference of that, if you wanted the -- the rate
17 impact test to really be at a rate payer, all rate
18 payer test, sort of as I think you're trying to get
19 at, you'd have to include that in the numerator as
20 well, and then it would wash out.

21 COMMISSIONER CHRISTIE: I'm just asking,
22 this is supposed to be a cost benefit exercise and --
23 and it should actually be fairly simple, I don't know
24 who invented these things, but -- but you -- you add
25 up the benefits and you -- and you scrub them, and you

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1 look and see, you know, how rigorous they are, and
2 then you say here's the benefits.

3 THE WITNESS: Mm-hmm.

4 COMMISSIONER CHRISTIE: And certainly if
5 you don't have to build a plant that's a benefit that
6 you can quantify, you know, if you don't have to buy
7 energy in the -- in the energy market, fuel -- fuel,
8 that's a -- that's a benefit, you know, you scrub it
9 and make sure you've got something that's not just,
10 you know, pure speculation, but that's a benefit, then
11 you look at the costs.

12 THE WITNESS: Yes.

13 COMMISSIONER CHRISTIE: Clearly when you
14 are compensating the Utility for alleged lost
15 revenues, especially on a prospective basis, and --
16 and -- and again, Mr. Jaffe's next witness is going to
17 -- goes into this, because there's a large element of
18 speculation built into it, but if -- but whatever it
19 is, it's a cost, it is going into rates, to say it's
20 not a cost, you know, if you want to -- if you want to
21 grab the avoided -- the avoided costs on the -- on the
22 numerator, if you want to grab that and say look at
23 all the stuff we didn't have to do --

24 THE WITNESS: Mm-hmm.

25 COMMISSIONER CHRISTIE: -- we didn't have

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1 to do, we didn't have to build a plant, we didn't have
2 to pay for fuel, if you want to grab that on the -- on
3 the benefit side --

4 THE WITNESS: Mm-hmm.

5 COMMISSIONER CHRISTIE: -- then you've got
6 to pay on the -- on the denominator side that you're
7 going to compensate the Utility for -- for alleged
8 lost revenues. So I mean --

9 THE WITNESS: I agree, but --

10 COMMISSIONER CHRISTIE: And it goes into
11 rates, people pay it, real people write real checks to
12 pay it, so you keep saying we -- we shouldn't -- we
13 should ignore it, but real people are going to write
14 the check to pay it.

15 THE WITNESS: They would have written the
16 check, anyway, though. It's not an added --

17 COMMISSIONER CHRISTIE: Well, first of all
18 -- well --

19 THE WITNESS: It's not an additional cost.

20 COMMISSIONER CHRISTIE: Well, If they're a
21 non-participant they wouldn't have written it, because
22 they're not getting this program. But --

23 THE WITNESS: Well, yes, if nobody had --
24 if there was no DSM program then there wouldn't be a
25 distinction between participants and non-participants

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1 and then everybody would be paying that same lost --
2 that same lost revenue, and -- and you -- you'd said,
3 I'm sorry, sir, you said it's prospective and -- and,
4 you know, we want to recover it in advance.

5 COMMISSIONER CHRISTIE: That's what
6 Dominion's asking, they're asking for prospective lost
7 revenue.

8 THE WITNESS: I understand that, my
9 understanding is that they're also proposed a
10 mechanism by which that would be adjusted if things
11 turn out differently than pro- -- than projected,
12 which -- which again, I think is also part of how
13 rates exist for a- -- for any part of their operation.

14 Again, if things turn out differently, I
15 mean, again, I guess I've been corrected on that, but
16 -- but to the extent that they're offering to say if
17 things turn out differently let's adjust it and change
18 it, and we'll either recover more or less depending
19 on, you know, evaluation that's done to the
20 satisfaction of all the parties, then -- then we'll --
21 we'll fix it, and -- and -- and I think that that's a
22 perfectly reasonable approach to -- to that.

23 Although, again, not my area of testimony,
24 but -- but, you know, to say we're going to make a
25 guess, do our best, you pay us the lost revenue, then

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1 we'll do evaluation, and we'll -- we'll do -- you
2 know, we'll -- we'll do that to the satisfaction of
3 everybody, and if there's a difference we'll -- we'll
4 adjust.

5 COMMISSIONER DIMITRI: When you say adjust,
6 do you mean --

7 THE WITNESS: Again, this is not my area,
8 maybe I shouldn't get into it, but I can leave it to
9 the other witness.

10 MR. JAFFE: Sorry if you --

11 COMMISSIONER DIMITRI: Well, do you think
12 it's a -- it means that in the future the program may
13 be structured differently to -- to deal with lower
14 savings or do you believe that customers are going to
15 get a refund for what they pay for and didn't get the
16 projected benefits for?

17 MR. JAFFE: Your Honor, I -- I -- and --
18 with respect to that, I think that does go more
19 directly to Mr. Powell's testimony, if you want to --
20 to get into how that --

21 COMMISSIONER DIMITRI: Okay. We'll wait.

22 MR. JAFFE: -- verification goes on.

23 THE WITNESS: I guess if I could just close
24 on saying I -- I think I understand your position,
25 Commissioner, in that -- that rate you're saying this

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1 is a real cost rate paper -- rate payers --

2 COMMISSIONER CHRISTIE: Well, I don't have
3 a position yet. I was just asking you questions.

4 THE WITNESS: You -- you made the statement
5 that if we give the Company lost revenue that's
6 something that's -- that's a cost to the rate payers.
7 And I'm -- I'm simply making the argument that they
8 were going to write those, they were going to spend
9 that money in either of these cases, it's not a new
10 cost.

11 And therefore, when you -- if you really
12 want to do all the benefits divided by all the costs
13 that result, that are different, doing DSM, not doing
14 DSM, the total resource cost test is the one that does
15 that for you.

16 COMMISSIONER JAGDMANN: Should the lost
17 revenues be subtracted -- subtracted from both sides
18 of the equation, then, if you're going to pay it in
19 either -- in either case?

20 THE WITNESS: I guess so, I think the --
21 the problem with that is that what you're saying --
22 sometimes it's easier to measure the change from a --
23 from case A to case B rather than measuring all of
24 case A and all of case B, to -- you know, one way of
25 doing this, that would make it clear, would be to say

1 what are the costs and benefits for everything that
2 Dominion does under no action and what are the costs
3 and the benefits of everything Dominion does under
4 delivering DSM. And then you'd look at the difference
5 between those two.

6 But the vast majority of all that stuff
7 doesn't change. The fact that they built plants and
8 they're recovering for them and they've -- you know,
9 got all the things that they've done haven't changed,
10 and so you're looking at what has changed.

11 BY MR. JAFFE:

12 Q Mr. Loiter, let me --

13 A Yes.

14 Q Just one very, very brief question on this
15 point, and then we can move on. Essentially, am I
16 correct that your point is that if in your no action
17 scenario the lost revenues are collected, and in other
18 words, by no action I mean no DSM programs implemented
19 at all, all programs rejected, the lost revenues that
20 are at issue here still get charged to rate payers but
21 they're just called revenues?

22 A Exactly.

23 Q Let me move on.

24 A Sure.

25 Q Also during yesterday's proceedings

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1 Mr. Newcomb explained that a score greater than one on
2 the Utility cost test meant that the DSM program would
3 be cheaper than the supply-side alternative.

4 Can you explain why this is so and what it
5 tells us about DSM as an energy resource comparable to
6 other supply-side options?

7 A I'm sorry, did you say that a -- a -- a RIM
8 test score of 1.0?

9 Q No, I'm sorry, if I did I misspoke, a
10 utility cost test score --

11 A Right.

12 Q -- of greater than one, I apologize.

13 A Right, a u- -- a utility cost looks at the
14 cost of delivering the energy solely from the
15 Utility's perspective, and so the numerator is, again,
16 the same benefits that Commissioner Christie noted and
17 the cost is the cost that the Utility incurs in
18 delivering that, which is their admin cost and any --
19 any incentive.

20 And so if -- from the Utility perspective
21 they can choose I can generate power with my coal
22 plant or my gas plant or whatever it is, or I can buy
23 energy on the market and -- and -- and the cost of
24 doing that is best represented by the information we
25 talked about in closed session, and when the Utility

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1 cost test is greater than one it's saying that the
2 cost of getting those -- that energy through the
3 program, it is less, and it's the cheap -- it's the
4 cheaper way to get -- to get the energy.

5 Q So in other words, if -- if we were to view
6 this whole proceeding as really about the Commission's
7 application to go out and get 800,000 megawatt hours
8 for the next several years --

9 A Mm-hmm.

10 Q -- the Utility cost test is telling us
11 whether the Company is getting a good price for that
12 800,000 megawatt hours or not?

13 A Yes.

14 Q And so if it's greater than one it's
15 cheaper than supply-side alternatives and it is a good
16 price?

17 A That's correct.

18 Q Mr. Carsley, on behalf of the Commission
19 staff, and Mr. Norwood, on behalf of the Office of the
20 Attorney General, both place a -- a great deal of
21 reliance on RIM. I think we've discussed this a great
22 deal already. So let me just get into some of the
23 specific RIM questions from their testimony.

24 A Sure.

25 Q Mr. Carsley, on page five of his testimony,

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1 states that reliance on the benefit cost ratio is
2 misleading, that net benefits would be more useful.
3 Do you have any response on that?

4 A Well, I -- I think it's a -- it's a -- it's
5 a -- a good point to keep in mind, that while the --
6 the actual ratio of benefits to costs is a convenient
7 shorthand to say do the benefits outweigh the costs,
8 it doesn't address the -- the magnitude of those
9 excess benefits or excess costs, and that if you look
10 at the results for the tests similar to what the
11 attorney for the Company put up a little while ago
12 you'll see that the net benefits from a total pers- --
13 resource perspective, which again, I believe is the
14 most appropriate way to sort of get at what's the
15 change for all of the Company's rate payers, that
16 those positive benefits far outweigh, you know, any
17 negative benefits to the non-participants as measured
18 by the -- by the RIM test. And -- and really shows
19 the -- the sizable economic return on this investment.
20 And so I would encourage the Commission to look at
21 those net benefits in terms of, you know, real
22 dollars.

23 Q Also, and sort of in ways of thinking about
24 RIM, Mr. Norwood makes the statement, and you just
25 referenced it already, that there will be little or no

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1 customer benefits from proposed DSM programs over the
2 next 15 years, you -- you suggest you think that's an
3 incorrect statement. Can you explain why you think
4 that's wrong?

5 A I believe it's wrong because the -- the
6 clearest way to assess the totality of net benefits to
7 all of the Company's customers is the total resource
8 cost test or the participant test, either one of which
9 shows dramatic net benefits.

10 And so there are clearly customer benefits
11 from these programs.

12 COMMISSIONER DIMITRI: That's assuming -- I
13 take it your opinion is -- is based upon the
14 assumption that all of the inputs to the model that
15 produce these numbers are accurate year after year;
16 right?

17 THE WITNESS: I would say that I have
18 pretty high degree of confidence that even if -- even
19 with some uncertainty in those inputs that there would
20 be net benefits in that if you look at the -- the --
21 the outcome of the total resource cost test for most
22 of these programs is substantial, that the -- the
23 uncertainties in any of these inputs, you know, are, I
24 think, highly unlikely to all go in such a way and to
25 such extent that this would -- that these would not be

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1 cost effective.

2 COMMISSIONER DIMITRI: Well --

3 THE WITNESS: It's like confidence that
4 even within the uncertainty that it's -- that it's
5 cost effective.

6 COMMISSIONER DIMITRI: In a net present
7 value analysis the -- the -- the early years of these
8 projected savings would be the most important,
9 wouldn't they?

10 THE WITNESS: That's correct.

11 COMMISSIONER DIMITRI: All right.

12 THE WITNESS: Yeah.

13 COMMISSIONER DIMITRI: And again, going
14 back to the natural gas prices.

15 THE WITNESS: Mm-hmm.

16 COMMISSIONER DIMITRI: As -- as an example,
17 if they are significantly different, significantly
18 lower --

19 THE WITNESS: Mm-hmm.

20 COMMISSIONER DIMITRI: -- than what's used
21 in the -- in the projections, then the benefits in
22 these early years, if any, would be significantly
23 lower, as well, wouldn't they?

24 THE WITNESS: As I testified earlier, no.
25 I don't believe that the connection between the

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1 short-term natural gas prices and the -- the benefits
2 as measured by the avoided energy costs, that there's
3 not such a clear short-term connection.

4 The value -- the price, you know, if you go
5 -- if you go on the -- the -- see that the spot price
6 of gas has dropped by ten percent in one day I don't
7 believe that if you go to PJM and look at the clearing
8 price of energy that you're going to see that the
9 clearing price of energy went down 10 percent that
10 day, as well. That they're -- I don't believe they're
11 going to follow one another like that.

12 Certainly, again, lower natural gas prices
13 will decrease the market price of energy, but not one
14 for one, not in -- in immediate term, that the market
15 energy price is based on so many other factors that
16 it's, you know, it's smoother, doesn't respond as
17 fast, and it's not solely driven by the natural gas
18 prices.

19 BY MR. JAFFE:

20 Q One more question on -- on the RIM test.
21 Mr. Norwood seems to be arguing for -- for giving the
22 RIM an exclusive veto on -- on these programs, what is
23 your sense of the -- of the -- of what -- is -- is RIM
24 given this kind of veto power in any other state that
25 you're aware of?

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1 A No. Nowhere else is, and -- and -- and a
2 -- a review of a -- of a -- a report released by the
3 American Council for Energy Efficient Economy that
4 surveyed policies for evaluation of -- of -- of rate
5 payer funded efficiency programs, they did -- they
6 looked at, I believe, the total sample was 41 states,
7 and found that the RIM test was used as the primary
8 test in only one state.

9 Q Let me move on, now, to some of the
10 specific program issues. You discuss flexibility in
11 the spending caps in your -- in your testimony, can
12 you just briefly explain why that's important?

13 A Sure. As I -- as I said in my testimony,
14 you know, I did support the -- the Company's request
15 that they be given flexibility in -- in both spending
16 cap, to a certain extent, and to be able to shift
17 funds from -- from one program to another in response
18 to customer uptake and market conditions and -- and --
19 and such.

20 And -- and I absolutely support that, you
21 know, it's certainly true that there's learning to be
22 done in getting these programs out there and it's
23 important that, you know, any business have
24 flexibility to -- to respond to their market and their
25 customer based on what they learn as they start to

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1 deliver a product or sell a service.

2 And so to the extent that this approval
3 period lasts for -- for three years or five years, it
4 -- that's too long a time to wait for the -- the
5 Company to have to come back to the Commission and
6 say, well, you know, looks like this program's really,
7 you know, this program is really getting a lot of
8 uptake and this one's not so much, so we'd like to
9 shift a little more money.

10 They -- they should have the flexibility to
11 do that to maximize the -- the use of those funds and
12 to get the most, you know, bang for the buck.

13 Q Just a -- a couple more questions.
14 Mr. Loiter, the Company's case also notes that -- and
15 this is discussed some in the -- in the responses,
16 that ICF used the Mid-Atlantic Technical Reference
17 Manual or TRM to estimate energy savings for
18 particular programs.

19 Can you just explain a little bit about
20 what the Mid-Atlantic TRM is?

21 A Sure. Technical Reference Manual is a term
22 that's used in -- in many jurisdictions to refer to,
23 you know, a set of information that guides how a -- a
24 utility and -- and commission and evaluators estimate
25 the savings from efficiency investments and -- and the

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1 measures that are installed as a result of the
2 efficiency programs.

3 The -- the Mid-Atlantic TRM is a product of
4 the Northeast Energy Efficiency Partnerships, which is
5 an organization that is funded by utilities and states
6 throughout the northeast. They have taken the
7 initiative to put effort into developing a -- a TRM
8 that could be used across jurisdictions to provide
9 some consistency in -- in how savings are measured and
10 counted, it was driven in large part by activity in
11 New England where the independent system, their
12 operator in New England wanted to see consistency in
13 the way efficiency programs in those six states were
14 -- were counting their savings.

15 So we worked on -- on studies related to
16 that, but then also got commitments from Maryland,
17 Delaware, and the District of Columbia to fund a -- an
18 effort to prepare a set of guidelines and -- and --
19 and a Technical Reference Manual about the savings
20 from common efficiency measures in those -- in those
21 -- in that region.

22 And that document was prepared, in part, by
23 other staff at Optimal Energy on -- on -- on some of
24 the commercial measures side. I -- I was not
25 intimately involved in -- in developing those, those

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1 savings algorithms that went into the TRM, but -- but
2 I do know that -- that the TRM's being used in
3 Maryland, and, in part, in the District of Columbia as
4 a basis for counting savings.

5 Q And lastly, with respect to the residential
6 bundle and the -- the synergies that come from having
7 bundled programs, Mr. Carsley, on -- on page 23 of his
8 testimony, states that a participating customer likely
9 will consider each program independently.

10 Can you respond to that?

11 A Sure. I don't think that that's a -- a
12 completely accurate statement. While it's certainly
13 true that customers, you know, may weigh certain types
14 of investments against one another, to the extent that
15 a customer is given a -- a -- a -- a menu of choices
16 from a -- from a comprehensive program or even, you
17 know, only -- only moderately comprehensive, a home
18 program, you know, best practice in -- in doing that
19 is to make it easy for the customer to engage with,
20 you know, one program through one channel and provide
21 them the opportunity to select among -- a bun- --
22 select amongst measures that address -- address their
23 needs.

24 It -- it may be sort of a fine distinction,
25 but the way I think of it is if you call these

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1 different measures, different programs, and -- and go
2 into a customer's home and say, well, you can do this
3 program or you can kind of go do that program, or you
4 can kind of go do that program, it's like going in to
5 buy a car and picking the base model and then having
6 the salesperson say, well, if -- if you want the
7 leather seats, go talk to that person and write them a
8 check, and if you want the upgraded radio with, you
9 know, satellite and navigation go talk to that person
10 and write them a check, you know, and if you want --
11 you -- you -- that's not the way it's done. People
12 are choosing from menu options, and they -- and they
13 may choose one or more that work best for them.

14 But in an efficiency program they're going
15 to be guided by the findings and the guidance of the
16 -- the program, who -- whoever they're interacting
17 with, to -- to deliver that program. And it's
18 important, I think, especially in the residential
19 realm, to present those options as parts -- parts of a
20 whole rather than a series of individual decisions to
21 be made.

22 Getting someone to make a decision, to do
23 anything, you know, takes effort and that's, you know,
24 that's why business is advertised in market and such,
25 to the extent that the efficiency program has a

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1 customer that's ready and willing to -- to do
2 something, that should be looked at as let's -- this
3 is one decision, we've got them, and -- and -- and now
4 let's get them what they need rather than a series of
5 individual decisions. I think that's an important
6 sort of mindset and framework for program delivery.

7 Q And -- and so just to finish your new car
8 purchase example, in response to Mr. Carsley, that if
9 you had to go with your new car purchase and to a
10 different dealership for each individual option you
11 wanted to add to that car, that -- that's identifying
12 that -- the siloing problem that you've talked about;
13 is that right?

14 A Right, that'd be a -- sort of a -- a hurdle
15 to -- to -- to participation or a barrier to
16 participation, it's, you know, additional
17 transactions. There's transaction costs, there's, you
18 know, decision, you know, decision cost to be done.
19 And so it's better to have it, you know, fewer
20 decisions rather than more and keeping them separate
21 like that.

22 MR. JAFFE: Yeah, amazingly enough the
23 witness is available for cross.

24 COMMISSIONER DIMITRI: All right. We're
25 going to take a 15 minute break before we start

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1 cross-examination.

2 (Recess.)

3 COMMISSIONER DIMITRI: All right. We're
4 ready for cross-examination of Mr. Loiter, is that
5 right?

6 MR. JAFFE: That's correct, Your Honor.

7 COMMISSIONER DIMITRI: All right.

8 Ms. Pierce.

9 MS. PIERCE: Yes, thank you, Your Honor.

10 CROSS-EXAMINATION

11 BY MS. PIERCE:

12 Q Still good morning, I do have several
13 questions for you.

14 You stated in your testimony, and I believe
15 also on the stand, that you do not think the RIM test
16 should be accorded the primary importance that it has
17 been given; is that correct?

18 A That's correct.

19 Q Okay. Are you aware that in 2009 the
20 Commission initiated an actual proceeding and sought
21 input from various representatives, including
22 utilities, for its determination as to what weight the
23 different cost benefit measures should be given in
24 analysis of DSM programs?

25 A Yes. And if I understand your question, I

1 think I testified in that proceeding.

2 Q Yes.

3 A If you're -- that's the one you're
4 referring to, yes.

5 Q Okay. Thank you.

6 A Mm-hmm.

7 Q And I believe this morning you indicated
8 that you believe that -- that there may be forecasts
9 and/or uncertainties do occur with forecasting; is
10 that correct?

11 A Yes.

12 Q Would you agree that the further out you
13 forecast something the more uncertainties there are
14 likely to be, just generally?

15 A All else equal, yes.

16 Q So would you agree, then, that if you
17 forecast something for year -- a year 25, that there
18 are more likely to be uncertainties in that year than
19 there would be in the forecasts for year 15?

20 A Yes.

21 Q Okay. Thank you. There's been quite a bit
22 of discussion this morning about the RIM test, and
23 I'll try not to go over the same grounds, but
24 regardless of your position as to whether or not --
25 not lost revenues should be included as an actual cost

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1 of DSM you do acknowledge that the RIM test is the
2 only, of the four cost benefit tests, that
3 incorporates the lost revenue component?

4 A I think that's true, subject to one caveat,
5 which is that other tests, when they draw the
6 boundaries, draw them such that lost revenue would
7 appear sort of on both sides of the issue. But -- but
8 yes, it's the only one that calls it out specifically.

9 Q Okay. Thank you. And I believe you also
10 said that the RIM test really looks at rates and the
11 rate impact; is -- is that your position?

12 A Yes.

13 Q And would you agree with me that for
14 customers, for Dominion's customers, the rate impact
15 of this case is very important?

16 A I would say that for the customer base, as
17 a whole, no, the rate impact is not very important. I
18 would say that the overall impact on energy cost is
19 what's most important for the customer base and the
20 overall impact on energy bills is what's most
21 important.

22 Q But you acknowledge with the approval of
23 DSM programs there certainly is a rate impact
24 component and the customers will see that?

25 A That's correct, if all other things equal,

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1 if the Utility sells fewer KWH and are allowed to, you
2 know, adjust their rates so that they're, you know,
3 made whole and get the revenue that they otherwise
4 would have gotten, the rate per KWH will have to go
5 up, yes.

6 Q Okay. And I believe in -- as revised in
7 its rebuttal, with this case, Dominion -- the average
8 residential customer using a thousand kilowatts per
9 hour a month would see an impact immediately of \$1.10?

10 A Is that a monthly or an annual?

11 Q That's the -- that's a per month.

12 A I don't have that number in front of me,
13 that sounds like what I -- what I reviewed in the
14 documentation.

15 Q Subject to check?

16 A Sure.

17 Q My point simply being that if it is
18 approved there will be an immediate or fairly
19 immediate cost increase as a result of the approval?

20 A There will be a rate increase and for some
21 customers there will be a bill increase. And for
22 other customers there will be a bill decrease. And
23 the bill decreases will outweigh -- outweigh the bill
24 increases.

25 Q And are you assuming or do you mean to say

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1 that the bill decreases will be for those who
2 participate in the programs?

3 A That's correct.

4 Q Okay. So for the non-participants there
5 will be an increase?

6 A For non-participants --

7 Q Bill increase?

8 A -- if they don't change their consumption
9 and rates do go up, then yes, their bi- -- their bill
10 will have to go up.

11 MS. PIERCE: Okay. No further questions,
12 Your Honor.

13 COMMISSIONER DIMITRI: Ms. Adams?

14 MS. ADAMS: Thank you.

15 CROSS-EXAMINATION

16 BY MS. ADAMS:

17 Q I just wanted to clarify, you had mentioned
18 that with regard to a bill increase for Dominion
19 customers, that -- did you say that they wouldn't be
20 as concerned about that as an energy bill increase?

21 A No. I'm -- what I'm saying is that for the
22 customer base, as a whole, seems to me that the most
23 important thing is what are the total bills for
24 energy, not what is the rate per unit of energy. I
25 mean, we could change billing from KWH to megawatt

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1 hours, and charge people a thousand times as much per
2 megawatt hour, that would be a rate increase but their
3 bill wouldn't change. So you know, what's relevant is
4 the amount of money being spent, not the per KWH,
5 looking at the customer base as a whole.

6 Certainly for an individual customer
7 they're correlated, but again, these programs,
8 overall, cause customers to spend less money on
9 energy.

10 MS. ADAMS: No more questions, thank you.

11 COMMISSIONER DIMITRI: Ms. Link?

12 MS. LINK: Thank you, Your Honor.

13 CROSS-EXAMINATION

14 BY MS. LINK:

15 Q Good morning, Mr. Loiter.

16 A Good morning.

17 Q I first want to talk a little bit about
18 your last statement. And you -- you made a
19 distinction between rates changing and overall impact
20 on energy cost and energy bills?

21 A Yes.

22 Q Do you recall that? Okay. And I'm going
23 to put on the screen, and this is from the direct
24 testimony of Company Witness Newcomb, which is Exhibit
25 9, and it is his schedule 13, which are the cost

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1 benefit evaluation results?

2 A Mm-hmm.

3 Q Do you see that?

4 A Yes.

5 Q Okay. Have you seen that before?

6 A Yes.

7 Q Okay. And I understand that this has been
8 slightly amended in rebuttal, but for purposes of our
9 discussion we can use this, this chart.

10 And when we talk about whether a DSM
11 program is cheaper than another alternative, meaning a
12 supply-side alternative or a market purchase?

13 A Mm-hmm.

14 Q It would be most accurate to look at the
15 Utility cost test, would you agree with that?

16 A Yes, from the Utility's perspective, that's
17 right, that -- that's the one that directly measures
18 the -- the difference in the cost of the program
19 versus the supply-side approach to -- to -- to meeting
20 those energy needs.

21 Q So when we talk about whether DSM is the
22 lowest cost alternative as compared to a supply-side
23 resource or a market resource what we would be looking
24 for is a score above 1.0 on the Utility cost test?

25 A That's correct, yeah.

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1 Q And all of the programs score above 1.0 and
2 some well above that --

3 A Yes, mm-hmm.

4 Q -- point; correct?

5 All right. On another topic, you had a
6 discussion with Judge Dimitri with regard to the early
7 years of the programs and within -- specifically with
8 relationship to the gas prices in the early years?

9 A Mm-hmm.

10 Q And when I said early years, let's, for
11 purposes of our discussion, limit it to 2012 and
12 2013 --

13 A Okay.

14 Q -- and the importance of the early years
15 and the -- the -- the forecasting accuracy in those
16 early years; do you remember that discussion?

17 A Yes.

18 Q Okay. And right now we're in March of
19 2012, and what is your understanding if you -- of when
20 these programs, if approved, will be implemented in --
21 in Virginia?

22 A I think I've seen tables that show them
23 beginning in May, if that -- and --

24 Q All right. So sort of mid 20- -- 2012?

25 A Yes, yeah, subject to checking, but yeah.

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1 Q All right. And then by mid 2013 would you
2 expect those programs to be sort of in the initial
3 phases of ramping up, meaning a -- a year into the
4 programs would be -- would the Company be ramping up
5 those programs?

6 A I -- I would expect that in -- in a year
7 there would, you know, there should be some decent
8 program activity, but -- but probably not, sort of,
9 you know, full out run. So it'd be somewhere along
10 the trajectory towards, you know, your intended, you
11 know, rate of -- of, you know, participation, I would
12 think.

13 Q Right. So then in year 2014, would you
14 expect that they'd would be more fully ramped up?

15 A You know, yeah, if all goes well with your
16 implementation and your contractors and -- and all
17 that, yeah. I mean --

18 Q All right. So the early first couple of
19 years would be implementation time and ramping up?

20 A Right. There's usually a trajectory from
21 zero to, you know, wherever it is you're aiming for.

22 Q Right. And the study -- the Company
23 studied these programs, as well as the supply-side
24 alternatives, over a 25-year study period; correct?

25 A You know, and I've got to say, in looking

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1 at the data that's presented I did have a little
2 confusion over what the assumptions were, and some of
3 the data, you know, say that you ran the tests for 25
4 years, but a lot of it looks like the vast majority of
5 the spending happens in the first five years, after
6 which the spending drops off dramatically.

7 Q But the savings, the savings from the
8 programs could be modeled over 25 years?

9 A Oh, yeah, absolutely, even if you did one
10 year of program and only did, you know, one -- one
11 year of things, you would want to use whatever the
12 appropriate lifetime of that measure is and make sure
13 you count the savings into the future from that, from
14 that measure.

15 Q So in terms --

16 A Even if you --

17 Q Yeah, finish your --

18 A Even in one year programs.

19 Q So in terms of long-term forecasting and
20 long-term modeling, if the first years, let's say the
21 first two years are ramp up and implementation, one
22 would expect that the -- the short-term swings we've
23 seen in the gas price forecast have to have a smaller
24 effect in those early years; would you agree with
25 that?

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1 A Well, short-term variability in a natural
2 gas price, again, is going to create some small --
3 some change of -- of -- in determined magnitude, I
4 think, in -- in the energy price forecast. And that
5 energy price forecast is relevant for many years going
6 forward.

7 So to the extent that short-term
8 variability, that there is short-term variability,
9 it's a small piece of the overall benefit stream of
10 measures that last for 10 or 15 or -- or 20 years.

11 Q Right. But my -- my question was related
12 to, if -- if the first two years of the program are in
13 building the participation levels --

14 A Right.

15 Q -- and implementation, and ramping up, if
16 there is a difference between what the Company modeled
17 and what is actually happening here in 2012, based on
18 the gas forecast, one would expect that effect to be
19 small?

20 A But because you're saying that a relatively
21 small portion of the energy savings are accruing in
22 these first couple of years, and so the -- any delta
23 there only effects the benefits calculated on these
24 first couple years of program activity if the forecast
25 and the prices come closer together in the future then

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1 -- then that affects the later more larger fraction of
2 the -- the savings, is that -- is that sort of what
3 you're getting at? I mean, yeah, if you're -- if
4 you're only doing 10 percent of the measures this year
5 and next year then the -- the avoided costs this year
6 and next year are only relevant to ten percent of the
7 -- the benefits.

8 Q And so long as the forecast, as you said,
9 comes together in the later years then one would
10 expect the -- the short-term impacts to have been --
11 to been minimal?

12 A Yeah, that's true. I didn't estimate the
13 percentage of the savings that are happening the first
14 couple years, but there is some ramp up, yes.

15 Q Okay, thank you. Moving to a different
16 topic, I have a document that I'd like to hand out.

17 THE WITNESS: Thank you, sir.

18 By MS. LINK:

19 Q And let's put it up on the screen, this is
20 the California Standard Practice Manual, Economic
21 Analysis of Demand-Side Programs and Projects, dated
22 October 2001?

23 Mr. Loiter, is that the document you have
24 in front of you.

25 A I'm sorry, say -- can you repeat the

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1 question, please?

2 Q Is that the document you have in front of
3 you?

4 A Yes, I have this, yeah.

5 Q Do you recognize it?

6 A Yes.

7 MS. LINK: Your Honor, may we have this
8 document marked for identification?

9 COMMISSIONER DIMITRI: It will be marked as
10 Exhibit 21.

11 MS. LINK: Thank you.

12 (Exhibit No. 21 was marked for
13 identification.)

14 BY MS. LINK:

15 Q Mr. Loiter, I put in front of you Exhibit
16 21, that's been marked for identification, and it is
17 the California Standard Practice Manual, and you said
18 you have familiarity with it?

19 A Yes.

20 Q And is this the practice manual that lays
21 out the different industry standard tests that we use
22 in DSM proceedings?

23 A Yes.

24 Q All right. And I believe there was some
25 discussion about who came up with these tests and

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1 where did they come from, so I'll ask you to turn
2 first to page one and we find out that the -- the
3 tests, Standard Practice Manual has come from
4 California; do you agree with that?

5 A Yes.

6 Q Okay. And, you know, when was it
7 developed, it appears that there was a void in termin-
8 -- in determining how these programs should be studied
9 and the initial publication in February of 1980 -- 83
10 helped to fill the void; do you see that?

11 A I see it, yes.

12 Q Okay. And then the practice manual was
13 revised in '87 and '88?

14 A I see that.

15 Q And then further changes to the manual were
16 -- were captured in this 2009, the -- excuse me, 2001
17 version?

18 A I see that.

19 Q Prompted by the effects of changes in the
20 NAFTA, electric and gas industries; do you see that?

21 A I do.

22 Q All right. And do you believe that this
23 2001 version to be the most current version of the
24 manual?

25 A Yes, actually, I -- it is.

1 Q All right.

2 A That's my understanding.

3 Q Thank you. I'm going to ask you to turn to
4 page two, and -- and the -- the title is demand-side
5 management categories and program def- -- definitions.
6 And it states: One important aspect of establishing
7 standardized procedures for cost effectiveness
8 evaluation is the development and use of consistent
9 definitions of categories, programs, and program
10 elements; do you see that, sir?

11 A I do.

12 Q So in effect, what this manual has
13 developed is a consistent way to identify programs,
14 program elements. And in establishing the four tests
15 it tells practitioners in this area what's appropriate
16 to include in the test, what's not appropriate to
17 include, so that when you take a TRC from one state to
18 another, one jurisdiction to another, you can know
19 that what's baked into those results has some level of
20 standardization; correct?

21 A That's correct.

22 Q Now, I'm going to ask you to turn to page
23 18, and there we talk about the total resource cost
24 test. And I think we've had quite a bit of
25 conversation about that today?

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1 A Yes.

2 Q And there in the first highlight section I
3 -- I believe your conversation with Judge Christie
4 alluded to this, but there it says, "The total
5 resource cost test measures the net cost of a
6 demand-side management program as a resource option
7 based on the total cost of the programs including both
8 the participants and the Utility cost"; do you see
9 that?

10 A Yes.

11 Q And I believe, in shorthand, people believe
12 that the TRC test is -- is, in a way, a combination of
13 the participant test and the Utility test; correct?

14 A That -- that's -- that's correct.

15 Q All right. And I do believe, then, there
16 was a great deal of discussion, both yesterday with
17 the Company witnesses and today with you, about
18 incorporating the effects of lost revenues into the
19 TRC test; do you recall that?

20 A Yes.

21 Q And whether or not it's appropriate?

22 A That's correct, yeah.

23 Q All right. And I do believe there was some
24 discussion about whether it -- it is a wash or whether
25 it's been -- there are offsets. And -- and the --

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1 whether the inclusion, and I believe you said that, in
2 response to cross-examination from the Attorney
3 General, I believe you said there was a caveat, other
4 tests would appear, a lost revenues would appear on
5 both sides of the issue; do you recall that?

6 A Yes.

7 Q And when you say in other tests lost
8 revenues would appear on both sides of the issue are
9 you referring to the TRC tests?

10 A In part, yes.

11 Q Okay. And so I'm -- I'm going to point you
12 to this language I've highlighted here in the beg- --
13 in the middle of the page, with regard to benefits and
14 cost. Can you take a moment to read that?

15 A Would you like me to read it out loud? Or
16 just --

17 Q No. You -- you can read it to yourself.

18 A Okay, I've -- I've reviewed it, yes.

19 Q Okay. And what this sentence says, that
20 the test is a combination of the effects of a program
21 on both the customers' participating and those not
22 participating; do you agree with that?

23 A Yes. The total resource cost test is
24 intended to look at the costs of the program and the
25 benefits of the program to everyone.

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1 Q And it says, in a sense it is the summation
2 of the benefit in cost terms in the participant and
3 the RIM tests where the revenue or bill change in the
4 incentive terms intuitively cancel, except for the
5 differences in net and gross savings; do you see that?

6 A I see that, yes.

7 Q And this sentence is meant to reflect the
8 notion where you said that the lost revenues would
9 appear on both sides of the issue, this sentence is
10 meant -- it calls it intuitively cancel, but that's
11 intending to reflect the same notion; correct?

12 A That's my understanding of what this --
13 this says, yes, and that, for example, if you look at
14 the cost to participants and non-participants and the
15 benefits to participants and non-participants,
16 altogether, then there are some expenditures or
17 receipts that are transfers from one group to another,
18 that's also true when you think about the participants
19 in the Utility, as well.

20 Q So in -- in your field you call these
21 transfer payments?

22 A That's right.

23 Q And the notion is that on one side of the
24 equation if it is a -- if -- if your cu- -- if the TRC
25 test is co- -- is combining the participant and RIM

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1 test, if the RIM test includes lost revenue as a cost
2 to the Utility and the participant test includes --
3 gives bill savings to the customer, those are the two
4 things that are intuitively cancelling; correct?

5 A Yes, that's right.

6 MS. LINK: All right. That's all I have,
7 for now. Your Honor, may I move the admission of
8 Exhibit 21?

9 COMMISSIONER DIMITRI: Hearing no
10 objection, Exhibit 21 is admitted.

11 (Exhibit No. 21 was received into
12 evidence.)

13 COMMISSIONER DIMITRI: Redirect?

14 MR. JAFFE: Just two very brief points or
15 questions.

16 REDIRECT EXAMINATION

17 BY MR. JAFFE:

18 Q In response to the question from the Office
19 of the Attorney General, Mr. Loiter, you stated that
20 rate impact is not important because people pay bills,
21 not rates; is that correct?

22 A I think I said I felt that the bill impact
23 was more important than the -- than the rate, but
24 ultimately yes, people pay -- pay bills.

25 Q And if Dominion decides to build another

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1 power plant, and that gets approved, all customer's
2 rates would increase. There'd be a rate impact for
3 everybody; correct?

4 A Likely, yes, new generation typically costs
5 more than the, you know, the current average cost of
6 -- of everything else they do, so typically rates have
7 to go up with --

8 Q And you can't get something for nothing;
9 correct?

10 A Typically not.

11 Q So if the DSM portfolio here is rejected
12 outright the Company's going to have to go out and get
13 that 800 gigawatt hours somewhere else; right?

14 A That's correct.

15 Q And every other supply-side option, even if
16 we take into account lost revenues, would be more
17 expensive for Dominion Virginia Power's customers; is
18 that correct?

19 A I believe that's the case, yes.

20 MR. JAFFE: No further questions, Your
21 Honor.

22 COMMISSIONER DIMITRI: All right. Thank
23 you, Mr. Loiter.

24 THE WITNESS: Thank you.

25 MS. TAUBER: Your Honor, environmental

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1 respondents would like to call Mr. Hale Powell to the
2 stand.

3 COMMISSIONER DIMITRI: All right.

4 HALE POWELL

5 having first been duly sworn, testified as follows:

6 DIRECT EXAMINATION

7 BY MS. TAUBER:

8 Q Mr. Powell, would you please state your
9 full name and business address for the record?

10 A My name is Hale Powell, my business address
11 is 20 Acton Road, in Westford, Massachusetts.

12 Q And on whose behalf are you testifying?

13 A I'm be- -- testifying on behalf of the
14 environmental respondents.

15 Q And by whom are you employed?

16 A I'm employed by H. Powell Energy Associates
17 at that address I referred to earlier.

18 Q Okay. And Mr. Powell, could you please
19 provide a brief summary of your qualifications as an
20 expert in this proceeding?

21 A Yeah, I've been involved in energy
22 efficiency programs pretty much exclusively for 30
23 years. The biggest piece of that was ten years
24 working for National Grid USA, which serves customers
25 in four states in the northeast, and has basically the

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1 largest set energy efficiency programs in the United
2 States. I worked within their programs for a period
3 of ten years; following that I worked for NEEP, which
4 is the organization referred to earlier, which
5 developed the Mid-Atlantic Technical Reference Manual;
6 following that I've been a independent consultant.

7 And in the last four or five years I've
8 been heavily involved in ener- -- energy efficiency
9 program and policy development in the Southeast.
10 Currently I'm working in about nine states, both in
11 collaborative stakeholder processes, working for
12 utilities or working for consortiums of utilities.

13 Q And Mr. Powell, did you prepare and cause
14 to be pre-filed in this docket on January 18th of this
15 year, direct testimony consisting of 38 pages in
16 question and answer format and six accompanying
17 exhibits?

18 A Yes, I did.

19 MS. TAUBER: And Your Honor's, I'll just
20 note that due to technical difficulties, environmental
21 respondents were unable to electronically file by the
22 17th the filing deadline and were granted leave to
23 file on the 18th.

24 COMMISSIONER DIMITRI: All right.

25 BY MS. TAUBER:

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1 Q Mr. Powell, do you have any corrections or
2 clarifications to your testimony?

3 A Yes, I do. Let me pull those up, here. I
4 had -- I had a few. In terms of corrections, on page
5 22, footnote 21, the second sentence should read:
6 This study indicated that internal utility staffing
7 levels, should be one utility FTE for each one to
8 three million dollars in total program expenditures.
9 Another correction is on page 34 --

10 COMMISSIONER DIMITRI: I'm -- I'm sorry,
11 can you just --

12 MS. TAUBER: Just slow down. And --

13 COMMISSIONER DIMITRI: Can you repeat that,
14 that's footnote 21 on page 22?

15 THE WITNESS: Yeah, do you want me to
16 repeat the -- repeat the sentence?

17 COMMISSIONER DIMITRI: Yeah.

18 THE WITNESS: Okay. The second sentence
19 should read: This study indicated that internal
20 utility staffing levels should be one utility FTE for
21 each one to three million dollars in total program
22 expenditures.

23 BY MS. TAUBER:

24 Q So Mr. Powell, instead of between one and
25 three FTEs for each million --

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1 A Correct.

2 Q -- it's one FTE for each one to three
3 million?

4 A That's correct.

5 Q Okay. Any other corrections?

6 A Another correction would be on page 34, in
7 the middle of the page, and I -- I apologize that the
8 line numbers were not printed on this testimony, in
9 the middle of the page in the paragraph beginning
10 with: It is also posi- -- possible that, the word
11 reduced should be deleted so that it reads: It is
12 also possible that higher tail block rates could
13 reduce the magnitude of customer incentives required
14 to induce participation.

15 In terms of clarifications, I have two,
16 first, regarding the program's proposal for additional
17 EM and V budget for the residential lighting program,
18 in the middle of page 14, my testimony states that you
19 cannot make a recommendation, can -- that I cannot
20 make a recommendation concerning the proposed
21 additional expensures -- expenditures because the
22 information was previously marked extraordinarily
23 sensitive.

24 My clarification is, I -- I do support
25 these additional funds for the EM and V, but note that

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1 the level of EM and V expenditures will reflect the
2 degree to which the various EM and V parameters, the
3 factors, can be stipulated to rather than measured
4 with full scale field data collection.

5 Q And you discussed that in other parts of
6 your testimony?

7 A I did.

8 Q Okay. Thank you.

9 A The second clarification is regarding the
10 Company's proposed EM and V plans, testimony -- my
11 testimony states on page 37, number B, that I'm
12 inclined to recommend approval of the proposed EM and
13 V plans subject to my review of information that was
14 labeled extraordinarily sensitive, also on page seven,
15 my clarification is that I do support the plans but
16 consider EM and V review, independent review of EM and
17 V results absolutely essential, and that's all my
18 clarifications.

19 Q Mr. Powell, other than those corrections
20 and clarifications, and -- and subject to a sur
21 rebuttal, if I were to ask you the same questions that
22 I -- that were put forth in your testimony at the
23 hearing today, would your answers be substantially the
24 same?

25 A Yes, they would.

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1 MS. TAUBER: Your Honors, I would ask that
2 the pre-filed direct testimony of Mr. Powell and his
3 accompanying six exhibits be marked for
4 identification.

5 COMMISSIONER DIMITRI: They will be marked
6 as Exhibit 22.

7 (Exhibit No. 22 was marked for
8 identification.)

9 MS. TAUBER: Thank you. And Your Honor, I
10 ask that -- I move their admission into evidence
11 subject to cross-examination.

12 COMMISSIONER DIMITRI: They will be
13 admitted subject to cross-examination.

14 (Exhibit No. 22 was received into
15 evidence.)

16 MS. TAUBER: Thank you.

17 BY MS. TAUBER:

18 Q Now, Mr. Powell, you mentioned in your
19 testimony that you didn't have -- you weren't able to
20 rely on extraordinarily sensitive material when you
21 filed your testimony; is that correct?

22 A That's correct.

23 Q And you now have access to the ES material?

24 A That is correct.

25 Q Now, without --

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1 MS. TAUBER: I don't believe we're planning
2 on going into any ES materials, Your Honor.

3 BY MS. TAUBER:

4 Q But without revealing any ES materials, do
5 you have any additional observations you would like to
6 make about Dominion's application?

7 A Yeah, my -- the one observation that --
8 that has subsequently -- the -- the prior --
9 previously was -- was ES re- -- designated was the EM
10 and V budgets and -- and in Mr. Jesensky's rebuttal
11 testimony, on page 16, he -- he did identify those --
12 those budgets as three percent of -- of program
13 expenditures, other than that, no.

14 Q Okay. And given -- given that knowledge of
15 the -- the three percent average, how do you respond?

16 A Well, I -- I would respond that -- that --
17 first that -- that -- that the three percent
18 expenditure for EM and V is -- is definitely on the --
19 on the low range of national practice, practices, and
20 I've been involved in a number of these discussions in
21 other jurisdictions, and have been involved in
22 national research about prevalent level- -- levels of
23 EM and V spending.

24 Three percent is really very much on the
25 low side, and particularly if you were to include the

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1 lost revenues as being -- that are being requested.
2 The actual three percent current expenditure request
3 for EM and V is only about two percent of the total
4 direct and indirect expenditures for the program.

5 So I -- I would recommend that it be
6 increased to a -- a level commensurate to that
7 prevalent in other jurisdictions.

8 Q Now, if you could just explain how spending
9 more on EMV would help with regards to keeping cost
10 effectiveness in check?

11 A Well, EMV has -- has two purposes, one is
12 to quantify the benefits of the programs in the sense
13 of EM- -- the actual -- the actual energy savings, not
14 the planned energy, or anticipated energy savings.
15 And in this state, those estimates will be used in the
16 calculations of lost revenue payments.

17 The other objective of EM and V that's very
18 core is to identify improvements in the program
19 operation, delivery -- delivery administration, and
20 management, and -- and identify those programs that
21 are ineffectively implemented or really are not
22 suitable to the target population in Virginia or
23 whatever state they're operating in, so it's a -- it's
24 a kind of a management implementation perspective
25 rather than a quantification of benefits perspective,

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1 so there are two objectives.

2 Q Mr. Powell, have you read the Company's
3 rebuttal testimony in this case?

4 A Yes, I have.

5 Q And the testimony filed by staff and the
6 AG's office?

7 A Yes, I have.

8 Q Now, some of the testimony addresses what
9 constitutes measured and verified in the context of
10 lost revenue recovery in Virginia, how do you respond
11 to that, that discussion in the testimony?

12 A Well, although -- although measured and
13 verified are not defined in the -- in -- in the
14 California statute in the -- or California practice,
15 in -- excuse me, not in California, Virginia statute
16 in the same way it's -- it's defined in -- in other
17 jurisdictions I -- I do believe that the -- the
18 language in the statute requires the measured and
19 verification to be -- to conform with those practices
20 in -- in -- in -- in -- prevalent in other utilities
21 and in the industry, generally.

22 And so I've had a lot of experience with
23 measurement verification in other jurisdictions,
24 including as a professional working for a large
25 utility company, and I think that one of the -- the

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1 elements that's missing in the measurement
2 verification roadmap, at this point, is independent
3 verification of -- of EM and V estimate, savings
4 estimates by a party that's independent, fully
5 independent of any contractual or financial
6 relationship with the party receiving the lost
7 revenue.

8 Q Now, Mr. Powell, there was also discussion
9 in that rebuttal test- -- in rebuttal testimony and
10 testimony of other witnesses concerning the use of
11 Virginia-specific data; do you recall those
12 discussions?

13 A Yes, I do. I -- I don't want to get into
14 too much in detail as a former EM and V professional,
15 but I -- I do have this to say about that, that --
16 that I'm on -- I'm unaware of any -- any jurisdiction
17 that requires that all EM and V, all factors that
18 contribute to the calculations of estimated savings
19 are state or jurisdiction specific.

20 Literally there are many hundreds of such
21 factors when you include all the measures and all the
22 types of programs that are offered, just for the
23 residential lighting program, for example, I believe
24 there's somewhat between eight and ten individual
25 factors, and that's just -- that's just for light

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1 bulbs.

2 So when you multiply that by all the
3 different measures you're talking about an enormous
4 mass of -- of data and -- and estimates. And it's
5 just, to me, it's financially un- -- un- --
6 unreasonable, and also it doesn't fit within the --
7 it's not compatible -- compatible with best practices
8 as established by regulators and utilities in other
9 jurisdictions, it's completely unnecessary.

10 With that said, I do believe that
11 Virginia-specific data is important, it's the question
12 is the matter -- the -- the issue of balance, to what
13 degree is Virginia-Specific data required or
14 advisable, and -- and to what degree is data
15 appropriately borrowed or modified from other
16 jurisdictions.

17 Q Thank you. Now, Mr. Norwood's recommend --
18 in his testimony, Mr. Norwood recommended against the
19 approval of EM and V plans until the Company's
20 collection and development of EM and D -- EM and V
21 data is completed and presented to the SCC; how do you
22 respond to that recommendation?

23 A I -- I don't believe you can measure
24 something that hasn't happened yet. I mean, EM and V
25 is primarily about assessing the impact of a program

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1 or measures that have been implemented, adopted by
2 participants.

3 And you cannot measure any of the factors
4 that -- that by -- by which energy savings are -- are
5 calculated without the actual participation and the --
6 of the -- and the installation of those measures. So
7 it's just not -- it's not practical, it's -- it's not
8 possible.

9 Q And also within the context of the
10 discussion of measured and verified, and the standard
11 that should be applied, Staff Witness Abbott discusses
12 the level of precision and mentions that meter usage
13 has a two percent precision level.

14 What is your opinion on that type of
15 percentage as it would apply to energy efficiency?

16 A Well, as a utility staffer and involved in
17 discussions, and development of EM and V protocols in
18 other settings, it's important to remember that --
19 that no uniform precision requirement is app- -- is
20 appropriate for every situation.

21 You certainly don't want to require the
22 same level of precision to a -- a small program where
23 you have a high certainty of, or a high confidence
24 level of -- of your savings estimates. You don't want
25 to apply the same level of precision to a -- that

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1 program as you would apply to a very large program
2 where there's a great deal of uncertainty about your
3 savings estimates.

4 So I -- I don't think it's particularly
5 relevant to compare a two percent precision level from
6 metering to, you know, to all programs to evaluations
7 of all programs.

8 I also note that there's definitely a -- a
9 -- an inverse relationship between precision --
10 precision requirements and costs of EM and V. The
11 greater -- the greater your precision requirements,
12 the -- the greater your sample size, the greater your
13 effort in producing the estimate.

14 And -- and we -- we need to be reasonable
15 about the level of EM and V expenditures. There
16 always is going to be a certain uncertainty in -- in
17 -- in the estimates of these -- of these program
18 savings.

19 Q And switching gears a little bit, you
20 discuss in your testimony, you bring up the issue of
21 the incentive structure in place, which is the margin,
22 and Company Witness Barker stated that the discussion
23 of the margin incentive structure is not appropriate
24 in this proceeding and is an issue for this
25 legislature; do you have any response to that?

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1 A Yeah, I -- I think it's -- I actually think
2 that it is quite relevant because the incentive
3 structure, as I understand it in -- in the state of
4 Virginia, is -- is very different from incentive
5 structures in -- in other states in that it -- it --
6 it basically is tied directly to the program
7 expenditures by Dominion.

8 So the more money Dominion spends they get
9 a margin on their expenditure as opposed to incentives
10 in other jurisdictions where the effectiveness of the
11 program, the performance of the program, the
12 administrative effectiveness or efficiency or the
13 level of savings are the determinant of the incentive.

14 In this -- in -- under this current margin
15 mechanism there is an incentive, a financial
16 incentive, unfortunately, for the Company to spend
17 money rather than develop and implement good programs,
18 so given that, I think that evaluation is particularly
19 important in -- in that environment.

20 Q Now, in light of the Company's response and
21 their rebuttal testimony, and specifically
22 Mr. Jesensky, to some of your concerns that you raise
23 about the EM and V process what is your opinion on
24 what the process should look like going forward in
25 terms of interaction with the stakeholders?

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1 A Well, I -- I've been working, just as a
2 very recent example, I've been working in a prolonged
3 process under the Arkansas Public Service Commission
4 in which we've -- the Commission established an EM and
5 V collaborative working group and we -- we produced,
6 or have produced, it's ongoing, protocols and, we've
7 developed a -- a mechanism by which independent review
8 is an actual entity was created to provide indepen- --
9 independent review.

10 What I would suggest was that the
11 Commission consider that sort of model for pursuing
12 any EM and V road map as -- as Mr. Jesensky indi- --
13 indicated in his direct testimony, that the Company is
14 open to working with respondents and -- and staff to
15 develop a road map, and I -- and I encourage that
16 development and I encourage the Commission to provide
17 some guidance as to where that development should go.

18 That being said, there are a number of
19 models of EM and V processes, in a variety of states,
20 and I did include as an exhibit some references to
21 that, and in -- and in specific a detailed document
22 produced by the Commission staff in -- in -- in
23 Maryland, which described different EM and V processes
24 and the inde- -- the -- the need for independent EM
25 and V review. There's lots of information available

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1 about different types of models.

2 MS. TAUBER: With that, Your Honor,
3 Mr. Powell is available for cross-examination.

4 COMMISSIONER CHRISTIE: Let me just ask him
5 a quick question, if you don't -- related to what you
6 just said about the -- in other states, in other
7 states, Mr. Powell, does -- does lost revenue include
8 profit for the Utility?

9 THE WITNESS: Well, it -- it -- it varies
10 by states, lost revenue, there's many different ways
11 of calculating lost revenue, some -- in some states
12 it's actually been a stipulated value --

13 COMMISSIONER CHRISTIE: Mm-hmm.

14 THE WITNESS: So it's difficult to give you
15 a uniform -- a -- a standard answer to that, and I
16 don't want to avoid the question, but it is --

17 COMMISSIONER CHRISTIE: Well --

18 THE WITNESS: And -- and I also -- I also
19 may say, relatively speaking, fairly few jurisdictions
20 address this issue by means of a lost revenue
21 mechanism.

22 COMMISSIONER CHRISTIE: Well, if you get --
23 if Dominion gets the regular base rate amount, let's
24 -- let's say 12 cents a kilowatt hour, the rate that
25 was set includes the rate of return, so then lost

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1 revenue, if you get full compensation for alleged lost
2 revenues, that would -- would include the rate of
3 return, because it's just in the -- in that amount,
4 wouldn't it?

5 THE WITNESS: Can -- can I -- can I just
6 make sure we're -- we're using the same terminology?
7 When I think base rate, the term base rate, to me, is
8 the -- that rate that's non- -- it's a -- it's a --
9 it's a non- -- the non-variable rate, it's the -- the
10 -- so typically rates are comprised in most
11 jurisdictions in base rates in a variable component
12 which includes fuel -- fuel costs. So --

13 COMMISSIONER CHRISTIE: Well, we do fuel
14 costs --

15 THE WITNESS: I just want to make sure
16 we're understanding each other in the -- in that
17 respect.

18 COMMISSIONER CHRISTIE: Okay, but in most
19 states if -- if -- if -- if -- if -- and -- and here
20 we do fuel in a separate mechanism --

21 THE WITNESS: Okay.

22 COMMISSIONER CHRISTIE: -- you know, dollar
23 for dollar recovery, but no return.

24 THE WITNESS: Right. Right.

25 COMMISSIONER CHRISTIE: But in a state

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1 where, you know, the lost revenue is based on, here's
2 your base rate, you get, you know, you're -- you're
3 approved, you're up, you know, you go through a base
4 case, you get a revenue requirement, based on that you
5 get 13 cents a kilowatt hours, what you get to charge
6 your customers.

7 THE WITNESS: Right.

8 COMMISSIONER CHRISTIE: And built on that
9 13 cents a kilowatt hour is your -- your -- your ROE.
10 I mean, that's -- that -- you're -- you're supposed to
11 get a return --

12 THE WITNESS: Right.

13 COMMISSIONER CHRISTIE: -- on that, as well
14 as, you know, cover the cost of you doing business.
15 So in your experience lost revenue does include, in
16 that scenario, if it's -- it would include profit,
17 right, because it's -- it includes the rate of return?

18 THE WITNESS: Well, again, it depends on
19 the state, and we have a very small sample here,
20 there's a very limited number of states that have lost
21 revenue mechanisms.

22 So again, I can't give you a -- a general
23 answer. In some states there's been an approval of
24 lost revenue recovery, but without specific filings by
25 the utilities which identify them, their -- their

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1 calculation, for example, in Arkansas, there's been
2 approval of lost revenue recovery, but the utilities
3 have not yet actually made the specific request for
4 recovery. So what they include and what the
5 Commission approves is unknown.

6 In -- in Ohio, for example, there was a
7 stipulated value for lost revenue, which doesn't break
8 down by different elements. So I'm -- I don't want to
9 avoid the question, it's just -- it's -- there's no
10 simple answer.

11 And in Virginia, the -- from my
12 understanding, the way that the Company has calculated
13 lost revenue is basically they've subtracted all their
14 variables costs, their fuel costs, their variable O
15 and M costs, and the off system sales opportunities,
16 and what's -- what remains is what they're -- they're
17 designating as lost -- as -- as lost revenues. And
18 presumably that would include -- include their return
19 on equity, as well.

20 COMMISSIONER CHRISTIE: Okay.

21 COMMISSIONER DIMITRI: We're ready for
22 cross-examination, Ms. Pierce?

23 MS. PIERCE: Yes, thank you, Your Honor.

24 ///

25 ///

1 CROSS-EXAMINATION

2 BY MS. PIERCE:

3 Q Good afternoon. I have just a few
4 questions for you. In your pre-filed testimony you
5 made the observation that Dominion's -- the amount of
6 lost revenues was -- and -- and I'm quoting, quite
7 high; is that correct?

8 A I -- I believe so, mm-hmm. The -- the --
9 the -- well, you'll have to -- you'll have to give me
10 the page number and --

11 Q Sure.

12 A But -- but I be- -- I believe that's the
13 sense of my testimony.

14 Q Okay. It's -- it's on page 15 about
15 middle -- middle of the way down?

16 A Okay.

17 Q If you would like to look at it.

18 A Okay, mm-hmm.

19 Q The sentence begins with second?

20 A Okay. Okay. Unfortunately, we don't have
21 line numbers here.

22 Q Yeah.

23 A But yes, I agree that there's significant
24 lost revenue at stake here.

25 Q All right. And then later on in your

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1 pre-filed testimony, going into page 25, at the very
2 top, you estimate that the cumulative -- cumulative
3 lost revenue for Dominion Virginia Power programs
4 would be roughly \$257 million dollars, and that is for
5 the five year pro- -- the five program years through
6 May 2016; is that correct?

7 A Yeah, mm-hmm. I mean, that's -- that's a
8 -- I think my -- the language I used was a rough
9 approxima- -- approximat- -- approximation.

10 Q Okay.

11 A Because I don't have -- that calculation
12 would involve information that won't be available for
13 five years down the line.

14 Q I understand. And to be fair, you were
15 basing your number on the lost revenue projection that
16 was in the original application; is that correct?

17 A Correct. I was assuming that the lost
18 revenue, the annual lost revenues in the original
19 application, of 25.6 million would be identical to
20 those that would occur in the subsequent four years.

21 Q Okay. Thank you. And one more question on
22 lost revenue, on page eight, it's in a Roman numeral
23 -- or number seven, the very last sentence, it's in
24 italics, you make the statement, without more
25 substantial and independent review of EM and V

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1 activities I do not support the recovery of lost
2 revenues through C2; is that a correct statement?

3 A That is correct, yes.

4 Q All right, thank you. And then finally on
5 or moving to EM and V, just briefly, I believe I
6 understood your clarification this afternoon that you
7 do support the EM and V plan, but kind of with a
8 caveat, that it should be subject to process
9 evaluation and more EM and V; is that correct? Is
10 that a correct statement?

11 A Well, that's not completely -- not
12 completely correct, the -- they're -- they're EM and V
13 plans.

14 Q Right?

15 A Those -- it's -- there's the EM and V plans
16 for each program --

17 Q Right?

18 A -- that were -- that were submitted. And I
19 -- I do support the a- -- the approval of those plans,
20 but I do -- my testimony is al- -- testimony also
21 states that they need to be supplemented with
22 additional, what I -- what are called process
23 evaluations to make them comprehensive.

24 Q Would it be your position, then, that if
25 there are areas of concern or -- or found in a process

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1 evaluation that the EM and V plan would be tailored to
2 address that or the actual --

3 A I'm sorry, I didn't quite hear.

4 Q Is it your -- is how -- how you see this
5 unfolding, then, is -- is as the process evaluation
6 takes place if there are any issues raised with how
7 the EM and V was -- was undertaken would -- would your
8 position or would your assumption then be that the EM
9 and V would be modified in -- in a way that would need
10 to be?

11 A Well, process evaluations don't evaluate
12 the EM and V process. Process evaluations evaluate
13 the programs and the program delivery.

14 Q And --

15 A So -- so EM and V, again, EM and V is made
16 up of -- of energy savings, estimate process,
17 estimation process, and also the source of program
18 efficiency implementation process evaluation. So --
19 so the --

20 Q And --

21 A -- process evaluations evaluate the
22 programs, not the EM and V.

23 Q Okay.

24 A So the quanti- -- what are called impact
25 evaluations.

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1 Q So -- and your position, then, is -- is you
2 would agree with the approval of the EM and V plan but
3 the process evaluation needs to continue?

4 A I -- I submit -- I -- I recommend the
5 approval of the plans.

6 Q Right.

7 A The plans that were submitted.

8 Q Right.

9 A Okay, there's multiple plans that were
10 submitted.

11 Q For each program?

12 A Yeah, there was program-specific plans. I
13 -- I recommend approval of those plans. But I
14 recommend this is supplementing those plans with --
15 with -- in effort to in- -- in- -- include process
16 evaluations to assess the eff- -- the actual
17 effectiveness, fuel effectiveness of the programs.

18 Q Okay. So there where -- through the
19 process evaluation there would be a continued
20 evaluation -- a process evaluation entails a -- an
21 eval- -- a continued evaluation?

22 A Yeah. Yeah.

23 MS. PIERCE: Okay, thank you. No further
24 questions.

25 COMMISSIONER DIMITRI: Ms. Adams?

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1 MS. POUILLE: Your Honor, the staff has no
2 questions.

3 COMMISSIONER DIMITRI: All right.
4 Ms. Macko?

5 CROSS-EXAMINATION

6 BY MS. MACKO:

7 Q Good afternoon, Mr. Powell, just following
8 up a little bit on a couple of things I heard you say
9 on your sur rebuttal.

10 One of the things you focused on was what
11 you call a missing part of the road map for
12 independent EM and V --

13 A Mm-hmm.

14 Q -- in your view, with -- and it -- and it's
15 your view that this entity could not be contractually
16 obligated to the Company in order to be truly
17 independent; is that fair?

18 A Well, I will -- I will respond to that by
19 saying that -- that it's really ultimately the
20 responsibility of the Commission to -- to define the
21 word or the term independence, and that that term is
22 defined -- been defined by different jurisdictions in
23 different ways.

24 In -- in -- very recently the Arkansas
25 commission has essentially def- -- it -- defined it in

1 a way you described, that -- that independent, the
2 independent, what's called down there the independent
3 evaluation monitor can have no contractual
4 relationships with those companies who are actually
5 implementing the programs.

6 Q But it -- it's possible, isn't it, that
7 this Commission could determine that an outside
8 vendor, separate and apart from the Company, could be
9 sufficiently independent to provide EM and V services?

10 A It's possible that Commission could
11 determine that, mm-hmm.

12 COMMISSIONER CHRISTIE: Well, let me ask
13 you, I was going to ask you about that anyway, looking
14 at page 19, where you talk about your recommendation C
15 up there, and I think that's what Ms. Macko was just
16 asking you about, so let me just ask you about
17 Arkansas.

18 When you say independent, and you say
19 separately contracted, you're -- you're saying that
20 the -- that the -- the vendor, the -- the monitor
21 should not be contracted by the Utility but then who
22 -- I mean, in -- okay, in Arkansas, who hires the
23 vendor?

24 THE WITNESS: The Commission staff
25 facilitated a process by which the stakeholder group

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1 wrote an RFP, evaluated the sub- -- submittals from
2 various EM and V experts, and selected -- selected the
3 vendor.

4 So the staff is the most direct client.
5 The expenditures are shared amongst all the -- all the
6 utilities in the state. So the client is -- is -- is
7 the staff and the Commission.

8 COMMISSIONER CHRISTIE: So the utilities
9 are still paying for the -- the monitor?

10 THE WITNESS: The rate -- the rate payers
11 are paying for the monitor.

12 COMMISSIONER CHRISTIE: Right, through the
13 utilities.

14 THE WITNESS: Through -- utilities are the
15 conduit for the rate payer money, correct.

16 BY MS. MACKO:

17 Q In following up on that, to the extent that
18 those additional costs were incorporated into the cost
19 benefit tests you would agree that they would
20 negatively impact them because there'd be an
21 additional cost?

22 A Not necessarily, I -- I think you -- you've
23 got to -- one has to realize that -- that evaluation
24 is not -- you can identify opportunities for
25 improvement of programs and make them more effective,

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1 and it doesn't necessarily en- -- en- -- entail a -- a
2 -- a decrement from -- from cost eff- --
3 effectiveness.

4 So the programs could be improved and --
5 and trimmed down, and won't be made more -- more
6 efficient as a result of that, that's not to say
7 there's not additional costs associated with -- with
8 -- in Arkansas or Maryland or in any of a number of
9 other states that have done an independent evaluation,
10 that's not to say there's not additional costs.

11 But there could be actually reduced costs
12 to rate payers if, for example, if the independent
13 monitor in Pennsylvania finds that the Company's
14 consultant has used an inappropriate statistical
15 model, and has overestimated savings and overestimated
16 lost revenue, that would reduce -- result in a
17 reduction of cost to the rate payers because the lost
18 revenue re- -- requests would go down.

19 So sometimes it would go up, and sometimes
20 it would go down, but it certainly would provide a
21 certain -- a much greater level of certainty that the
22 programs were effectively implemented and that
23 calculations for savings and lost revenues were
24 unbiased and objective.

25 Q And those cost savings that you're

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1 identifying in your response would come later, they
2 wouldn't be incorporated into the cost benefit test
3 that we're doing today; is that correct?

4 A No. There -- they would be included in,
5 prospectively, in -- in cost effectiveness analysis of
6 -- of future programs and the -- and -- and those cost
7 savings would be, more importantly, those -- those
8 opportunities for program improvement would be
9 reflected in improved program design of the -- of the
10 Company's programs.

11 Q Thank you. Another point I think you made,
12 we were talking about the incentive structure or you
13 were talking with your counsel about the incentive
14 structure, and talking about because the incentive
15 structure is tied to the level of spending that --
16 that you didn't believe it was properly structured?

17 A Well, I -- I would -- I didn't say it that
18 way, I -- I'm saying that it's atypical for incentive
19 structures around the country. I -- I think that one
20 of my exhibits did include some discussion of
21 incentive structures in other -- in other places and
22 they're typically tied to the program performance, not
23 the program expenditures.

24 And having worked in a utility company for
25 a long time I know that utility companies, like any

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1 other business, are in the business of maximizing
2 their revenue and -- and their profits.

3 So I think there's particu- -- that, to me,
4 points out the -- the particular need to have
5 evaluations of program effectiveness because of the
6 nature of this -- of this incentive in Virginia.

7 Q And are you aware, sir, that the
8 Commission, in approving the, what we've been calling
9 the DSM-1, Phase I programs that were approved in
10 2009, included with that approval specific spending
11 caps for the approved programs?

12 A I -- yes, yes, I am, I was actually
13 involved in that docket.

14 Q Thank you. And when you were talking about
15 lost revenues I believe you said that the -- that the
16 -- that the -- what -- what's being proposed in this
17 case is atypical to -- to what you've seen.

18 Is -- had -- have you seen other structures
19 where there has been a complete decoupling of
20 revenues?

21 A Oh, yeah, abs- -- absolutely, I forget the
22 number of jurisdictions now that have lost revenue
23 mechanisms around the country, maybe it's six, might
24 be as much -- as many as eight. When I worked for
25 National Grid, for years, in the initial years we had

1 a lost revenue mechanism in place, and that's been
2 superseded, as is true in many other states, by a
3 decoupling approach.

4 Q And the point of the -- of the lost revenue
5 mechanism is to remove the disincentive for the
6 Utility to undertake energy efficiency programs; isn't
7 that correct?

8 A Yeah. I -- and I fully support that, I
9 think that's a legitimate concern.

10 Q On page two of your testimony you state
11 that you participated in one of the Company's
12 stakeholder review process meetings?

13 A Mm-hmm.

14 Q Is that correct?

15 A I participated by phone, correct.

16 Q And the SRP is organized by and conducted
17 by the Company; is that correct?

18 A That's my understanding.

19 Q And on page 35 of your testimony, I'll give
20 you a second to get to. Are you there, sir?

21 A Yes.

22 Q You say, and this is the sort of in the
23 middle of the page, you say that, "The meetings are
24 relatively infrequent and have not allowed for a great
25 deal of detailed discussion and consensus decision

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1 making among the participants"; is that accurate?

2 A Well, that's -- that's what my testimony
3 says. Yes, that's my perception.

4 Q Would you agree that participation by
5 parties other than Dominion in the SRP is voluntary?

6 A Yes.

7 Q Dominion can't compel anyone to
8 participate, can they?

9 A No, they can't.

10 Q Would you agree that the interests
11 represented at the stakeholder review process have
12 included environmental interests, rate payer
13 interests, vendor interests, and the staff's of the
14 regulatory commissions in which the Company is
15 regulated?

16 A Since I didn't participate in -- in -- in
17 several of the -- the -- of the meetings, I can't
18 really attest to that, and I really don't remember the
19 -- the -- the participant list of those who
20 participated. So I'm -- I'm sorry, I can't really
21 answer that question accurately. I -- I can compare
22 that with stakeholder processes in other states in
23 which I've participated, though.

24 Q Would you agree that for consensus decision
25 making to occur that there needs to be general

1 agreement among the parties to -- to the process?

2 A Well, depends on how consensus is defined.

3 I -- there's been -- I've been in- -- involved in a
4 lot of discussions about this in different settings,
5 in general, I would -- I would agree, but consensus
6 can be defined by different parties in different ways.

7 Q Well --

8 A But generally, yes, gen- -- general
9 agreement is usually --

10 Q Consensus is needed?

11 A Is implied in -- in consensus, yeah.

12 Q And you're aware, in this case, that -- and
13 you've reviewed the testimony of the Commission staff
14 and the Office of the Attorney General in this
15 proceeding?

16 A Yes, I have.

17 Q And, in fact, the staff and consumer
18 counsel don't agree with the Company or even each
19 other on exactly which program should be approved; is
20 -- is that fair?

21 A I understand that, yes.

22 Q And there isn't a general agreement about
23 whether lost revenues should be approved here?

24 A I -- I believe that's true.

25 Q One of the points you -- I think you made

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1 on sur rebuttal was that the commercial or the CFL
2 study that we've been talking about, the additional EM
3 and V --

4 A Mm-hmm.

5 Q -- for the residential lighting programs,
6 Phase I and II, I believe your -- your position is
7 that the additional dollars should be approved subject
8 to continued negotiation over stipulated values; is
9 that accurate?

10 A I -- I believe so, yeah. Mm-hmm.

11 Q Are you aware that -- of discussions that
12 have occurred to try to -- to determine those
13 stipulated values?

14 A I remember one SRP meeting in which that
15 was -- that was discussed and -- but since then I
16 don't remember any -- any detailed discussion about
17 that, I do. Obviously, in my testimony, encourage
18 continued dis- -- discussion. But -- but I -- but I
19 must say that -- and -- and -- and remind the
20 Commission that I believe that that discussion was --
21 occurred right -- right before Thanksgiving. And
22 since Thanksgiving many of us have been very involved
23 in -- in preparing for this hearing providing
24 testimony. So I -- I don't think it precludes having
25 those discussions, at all.

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1 Q You would agree, at this point in time,
2 though, consensus has not been reached among the
3 stakeholders to stipulate any of those values?

4 A I don't think there's been a -- a -- a
5 focus in a -- my impression there has not been a focus
6 in a discussion to determine -- determine that, I have
7 had no discussions with the parties about any of those
8 specific parameters, so I don't think we've had a
9 substantial enough discussion to -- to determine that.

10 MS. MACKO: That's all the cross I have of
11 this witness.

12 COMMISSIONER DIMITRI: All right. Redir-
13 -- any redirect?

14 MS. TAUBER: No redirect, Your Honor.

15 COMMISSIONER DIMITRI: All right. We will
16 break for lunch and be back at 10 minutes after 2:00.

17 (Recess.)

18 COMMISSIONER DIMITRI: Ms. Pierce?

19 MS. PIERCE: Yes, Your Honor, the division
20 of consumer counsel calls D. Scott Norwood to the
21 stand.

22 MS. LINK: Your Honor, while Mr. Norwood is
23 taking the stand, we have had copies made of 20 and
24 20C, shall we hand them out now, or --

25 COMMISSIONER DIMITRI: Go ahead.

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1 MS. LINK: Thank you.

2 MS. PIERCE: Okay. And Your Honor, while
3 those are being handed out, I've conferred with
4 counsel, I will have very brief questions for
5 Mr. Norwood and his sur rebuttal of a confidential and
6 extraordinarily sensitive nature.

7 The proposal, after discussing with
8 counsel, is that we have him do public sur rebuttal,
9 then confidential sur rebuttal, then let there be
10 cross-examination on the confidential part, as well as
11 redirect, and then we go back onto the public re- --
12 record to finish public cross, trying to limit the
13 number of times we have to open and close the
14 courtroom.

15 Now, we are at -- at your discretion, we
16 can do it any other way, that is just our proposal.

17 COMMISSIONER DIMITRI: I hate to ask you
18 this, but could you explain that one more time?

19 MS. PIERCE: How many rounds? There will
20 be a public and confidential round for Mr. Norwood.

21 COMMISSIONER DIMITRI: Yeah.

22 MS. PIERCE: So the proposal is for him to
23 do public sur rebuttal, on the stand, then go into
24 confidential sur rebuttal, because I will have
25 questions for him on the confidential, then let there

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1 be cross, remaining confidential, so that there's
2 cross on the confidential information, and then we
3 open back up so that there's -- if there's any cross
4 on the public nature we allow that to happen.

5 COMMISSIONER DIMITRI: So the cross
6 wouldn't take place after he does his public sur
7 rebuttal?

8 MS. PIERCE: Correct.

9 MS. LINK: Your Honor, we've asked for that
10 accommodation in -- in order to be able to hear the
11 entire sur rebuttal before we begin our
12 cross-examination.

13 COMMISSIONER DIMITRI: All right. Okay.
14 Proceed.

15 MS. PIERCE: Thank you.

16 D. SCOTT NORWOOD

17 having been first duly sworn, testified as follows:

18 SUR REBUTTAL EXAMINATION

19 BY MS. PIERCE:

20 Q Good afternoon, could you please state your
21 name and address for the record?

22 A Yes, my name's Scott Norwood, my address is
23 9408 Belmont Drive, Austin, Texas.

24 Q And did you cause to be filed on January
25 17th, 2012, in this case, testimony consisting of 31

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1 pages of testimony and two exhibits?

2 A Yes, I did.

3 Q And do you have any corrections to your
4 pre-filed testimony?

5 A Yes, I have three corrections. The first
6 correction is on page 10, line three of the testimony,
7 the date there 2024 needs to be changed to 2013.

8 COMMISSIONER CHRISTIE: What's that?

9 BY MS. PIERCE:

10 Q Again please? Could you repeat that,
11 Mr. Norwood?

12 A Yes, page 10, line three, the date 2024 --

13 COMMISSIONER CHRISTIE: Mm-hmm.

14 A -- should have been 2013. The next change,
15 actually, there are two changes on lines three and
16 four on page 15, the first change on line three, after
17 the comma in the middle of the line, delete the words
18 only two, and add the word three, and then on line
19 four, between the words and, and those, at insert two
20 of, so that sentence in its entirety should read: As
21 summarized in table four below, three of the proposed
22 DSM programs pass the RIM test and two of those
23 programs have RIM test result -- RIM results only
24 slightly above the minimum 1.0 passing score.

25 The last change is on page 29, line five, I

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1 need to change the word loss, L-o-s-s, to lost,
2 l-o-s-t, and those are all my changes.

3 Q Thank you. And if I were to ask you the
4 same questions today that appear in your pre-filed
5 testimony, as corrected, would your answers be the
6 same?

7 A Yes.

8 MS. PIERCE: Your Honor, at this time I'd
9 like to ask that Mr. Norwood's testimony be marked as
10 the next exhibit. I will note that he has both a
11 public and a confidential version of his testimony.

12 COMMISSIONER DIMITRI: All right.
13 Mr. Norwood's direct testimony public version will be
14 marked as Exhibit 23 and the confidential version will
15 be marked Exhibit 23C.

16 (Exhibit No's. 23 and 23C were marked for
17 identification.)

18 MS. PIERCE: Thank you, Your Honor.

19 BY MS. PIERCE:

20 Q Mr. Norwood, were you present in the
21 courtroom this morning to hear the testimony?

22 A Yes.

23 Q And do you agree with the statement made by
24 Mr. Loiter that energy efficiency has lower cost than
25 market prices?

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1 A Well, again, I think this is a matter of
2 interpretation of what's -- what's the cost to rate
3 payers in this case. And I am viewing this in terms
4 of when the Company gets its rider approved and -- and
5 those rates are put into effect, what is that actually
6 going to cost customers, what are they going to pay in
7 order to achieve the forecasted energy reductions.

8 And if you look at the Company's testimony,
9 I know they're -- they're focusing on this initial
10 increase, but if you look at their projections, the
11 cost of this program over five years, the operating
12 expense projections are on the tune of about 185
13 million dollars, that's for the new programs, and the
14 loss revenues, this is the important thing to
15 remember, the lost revenue number discussed in the
16 case is about 12 million now, but projections over the
17 five years are approximately 330 million dollars of
18 lost revenues.

19 And so in essence what you're approving in
20 this case, if you approve it, is over 500 million
21 dollars over the next five years of cost of -- of
22 these programs capped and lost revenues based upon
23 Company's forecast.

24 And so if you look at that just roughly,
25 and say, over five years, 500 million dollars, that

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1 equates to about, relative to the amount of energy
2 that's being saved, which is roughly 3.7 million
3 megawatt hours, that equates to a cost per megawatt
4 hour of about \$135 per megawatt hour.

5 And so my view is, and we -- I know we have
6 a fundamental difference of opinion, but my view is
7 what rate payers are going to see for this energy
8 saved over the next five years under the Company's
9 forecast, and assuming these lost revenue numbers do
10 not go higher, because they certainly could, is a
11 power cost that are, you know, probably three times
12 what the current market is and so that's to achieve
13 the savings.

14 So in my view it's not -- well, in my -- in
15 my view it's -- it's not a good deal in near term,
16 that -- that the market rates are well below what it's
17 truly going to cost the customer to achieve these
18 savings.

19 COMMISSIONER DIMITRI: When you said near
20 term you're referring to the five-year period?

21 THE WITNESS: Yes.

22 COMMISSIONER DIMITRI: Okay.

23 COMMISSIONER CHRISTIE: Mr. Norwood, is
24 there anywhere in this record, this is going to
25 presume you've looked at everything, so I'm going to

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1 give you the credit for having looked at everything.

2 THE WITNESS: Right.

3 COMMISSIONER CHRISTIE: Is there anything
4 in this re- -- any chart in this record that does the
5 comparison that you just implicitly made, which is to
6 take the cost of this portfolio, everything they put
7 on the table, the whole cost, the cost of the program,
8 the cost of the lost revenue, the cost of the -- and I
9 know there's a debate over whether the lost revenue is
10 really a cost, but in coming up with a dollar per
11 megawatt cost of -- of electricity and then compare it
12 to, that alone would be helpful, because then you can
13 compare it to what we think the market price is going
14 to be, we know -- we can, you know, we know what the
15 market price per megawatt is in PJM today?

16 THE WITNESS: Right.

17 COMMISSIONER CHRISTIE: We can, you know,
18 in the next three to four years, we can always look at
19 what we think gas prices are going to, and they do
20 drive PJM, contrary to what a previous witness said,
21 they do drive PJM.

22 THE WITNESS: Right.

23 COMMISSIONER CHRISTIE: And then so, in
24 terms of comparison, because these -- these tests get
25 more confusing as you -- as you talk more about them,

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1 but if you just saw a dollar per megawatt for the cost
2 of electricity of this whole thing versus, you know,
3 then we can just -- is -- is -- is there anything in
4 the record that does that, because you implicitly just
5 did it with your -- with your cost per -- per
6 megawatt?

7 THE WITNESS: Well, the -- of course, there
8 is a VATER response that's highly sensitive, that
9 gives you most of the information you need, but to
10 compile it, as I just did, would take quite a bit of
11 time, because it was provided in a Word format, so you
12 can't just roll up the numbers.

13 But -- and that -- that is staff, they
14 request 1.2, if you want to look at it afterwards.
15 And in various other places they provide, for example,
16 the forecasted megawatt hour reductions. I think
17 Mr. Newcomb has that schedule in his testimony.

18 And with those two pieces of data I think
19 the Newcomb's forecast of megawatt hour reductions,
20 and the response to staff 1-2, plus the supplement,
21 you can -- you can make those calculations.

22 COMMISSIONER CHRISTIE: Because you'd have
23 to make all the assumptions that the measured and --
24 and verifiable, you know, reductions are, in fact,
25 what the measure is --

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1 THE WITNESS: Yeah, I mean, you'd still be
2 -- you'd still be --

3 COMMISSIONER CHRISTIE: I know, you still
4 have -- you still have assumptions --

5 THE WITNESS: Right.

6 COMMISSIONER CHRISTIE: -- you've got to
7 do?

8 THE WITNESS: Right. But if you wanted to
9 take face value, their forecast, and said, all this is
10 perfect, this is what the number would be, and you
11 know, my view on the front end it's -- you know, it's
12 very expensive, I have some, you know, schedule with
13 my testimony that show -- shows that, but it's -- it's
14 not -- it's not easily identifiable, but it could be
15 calculated if you asked for it.

16 MS. LINK: Your Honor, while we're on the
17 subject, this is the first we're hearing of
18 Mr. Norwood's calculation, and it would be helpful for
19 there to be work papers provided that support these
20 data that he has just presented to us for the first
21 time here today.

22 COMMISSIONER DIMITRI: You can pursue that
23 on cross-examination.

24 MS. LINK: Thank you.

25 THE WITNESS: Yeah.

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1 COMMISSIONER DIMITRI: Mr. Norwood, let me
2 make sure I understand, the 25.7 million dollars of
3 lost revenues, that's for the first year of the
4 programs?

5 THE WITNESS: Right.

6 COMMISSIONER DIMITRI: And as
7 implementation increases, is that why that number
8 would go up to the 300 million dollar level?

9 THE WITNESS: That's exactly why, yeah, you
10 heard the testimony, that first year we're ramping up,
11 so the savings are very small, so the lost revenues
12 are -- are small.

13 COMMISSIONER JAGDMANN: Mr. Norwood, were
14 you in the room -- I'm sure you were in the room when
15 there was a discussion about lost revenues and whether
16 you should count them or not. And I think you made a
17 reference to that in your testimony, that lost
18 revenues are only included in one part of the test.

19 As I understand this statement, the way the
20 tests are associated, you're going to have to pay
21 those lost revenues anyway, if there wasn't -- if
22 there were no DSM program, you would have to pay those
23 lost revenue programs anyway, so why are we counting
24 them, again? Why are we not just looking at the
25 incremental difference? So if we were -- if you're

1 going to have to pay it anyway, if there wasn't a
2 program, why should we pay attention to it?

3 THE WITNESS: Well, you know, I think it's
4 a -- the theoretical argument versus what's really
5 going to happen, in -- in my judgement --

6 COMMISSIONER JAGDMANN: You'd have to pay
7 the lost revenues anyway, is -- is that what's really
8 going to happen?

9 THE WITNESS: Yeah, what I -- what I'm
10 saying is, the argument on the other side is, well,
11 we'll have these reductions, and therefore we would
12 have had to immediately make those up anyway, the
13 Company would have been entitled to that, and
14 therefore paying them lost revenues is just paying
15 them that back -- back a little earlier than they
16 otherwise would received it, and that sounds fine in
17 theory, but as you and I know, rate making is more
18 complicated than that, the Company could now be over
19 earning, you know, for example they have low growth,
20 they have other things that change, that effect their
21 revenues.

22 And so, you know, to say -- to isolate one
23 change and say they would have, you know, with that
24 loss come in and obtained additional recovery to cover
25 that loss I think is unrealistic.

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1 There is some theoretical basis to that,
2 but I think in reality, to say that even though we're
3 charging customers 330 million dollars over the next
4 five years, they -- they would otherwise have to pay
5 that anyway, because of this program, is -- is not --
6 is not correct.

7 COMMISSIONER CHRISTIE: Well, let me ask
8 you, let's get up to the most basic level, it's true,
9 isn't it, that if you have a inefficient heat pump,
10 and Dominion gives -- gives you a cr- -- a coupon or a
11 credit or some form of incentive to put in a high
12 efficiency heat pump, and so with the inefficient heat
13 pump you are using a hundred kilowatt hours a month to
14 run that heat pump, and now with the high efficiency
15 heat pump you only need 90 kilowatt hours to run that
16 heat pump, and setting aside the issue of whether
17 you're going to increase your consumption because now
18 it's cheaper, just set -- set -- set that aside.

19 THE WITNESS: Right.

20 COMMISSIONER CHRISTIE: Hasn't Dominion --
21 isn't this the crux of their lost revenue argument
22 that -- that, you know, Dominion was selling a hundred
23 kilowatt hours to you to run your old heat pump, now
24 they're only going to sell you 90 kilowatt hours to
25 run your new, high efficiency heat pump. Therefore,

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1 they've lost 10 kilowatts of revenue. And there's no
2 incentive for them to do that, they're in the business
3 to sell electricity, let's face it.

4 So to make them incur that lost, by
5 incentivizing you, then -- and by -- and your side of
6 the coin is that, you know, they lost 10 kilowatt
7 hours of -- of revenue from you, but you gained it
8 because now you're not paying it, so i.e. it's a
9 wash --

10 THE WITNESS: Yeah.

11 COMMISSIONER CHRISTIE: -- for that
12 customer, right? I mean, isn't that true, I mean, at
13 the most granular level?

14 THE WITNESS: Yeah, there's some truth to
15 that, and I think the problem where this all breaks
16 down is, as you know, rate making is not that precise
17 where you can, you know, isolate on one -- one item
18 and one change and say, the loss there, you know, they
19 would have been entitled to and would have -- would
20 have recovered otherwise, and that -- that issue, plus
21 the issue of how you recover these amounts, you have
22 problems with, you know, people who don't participate
23 in these programs, in essence, funding losses created
24 by their -- by their customers.

25 COMMISSIONER CHRISTIE: Well, that's the

1 transfer issue, right, the cross subsidy?

2 THE WITNESS: Right.

3 COMMISSIONER CHRISTIE: And clearly there's
4 cross subsidies from non-participants?

5 THE WITNESS: Right.

6 COMMISSIONER CHRISTIE: But is that why you
7 don't -- in your -- in your whole testimony you
8 basically take anything with the RIM test that didn't
9 get one or above, as I read it, and you basically just
10 knock out anything that didn't have a RIM above one,
11 right, essentially?

12 THE WITNESS: Well, I --

13 COMMISSIONER CHRISTIE: Essentially?

14 THE WITNESS: I didn't mean it to come
15 across that way, but we have, as you know, have, in
16 past cases, have recommended --

17 COMMISSIONER CHRISTIE: Mm-hmm.

18 THE WITNESS: -- programs that have RIM
19 results below one, you know, and if they had very high
20 offsetting TR -- TRC score, but, you know, overall I
21 felt the -- the analysis, and we've talked about the
22 issues, had some problems in it, which inflated the
23 numbers. And so when I viewed the 1.0 results in the
24 testimony I -- I don't really view those as 1.0
25 results. But I --

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1 COMMISSIONER CHRISTIE: Well, there's --

2 THE WITNESS: -- do primarily, primarily,
3 but not entirely, rely upon RIM, because I think it's
4 -- it truly measures what customers are going to pay.

5 COMMISSIONER CHRISTIE: Well, doesn't the
6 TRC, I mean, it -- it -- it -- it does, doesn't the
7 TRC at least, I mean if it's a high TRC, and again,
8 assuming all the inputs are valid, you know, all the
9 forecasts are valid, all the inputs, and it's -- that
10 -- that can be questioned on its own, but that's a
11 separate issue about -- that applies to test, but
12 assuming all these number -- all the inputs are valid,
13 if a TRC is, you know, four, five, isn't that showing
14 certainly substantial benefit, at least to the
15 participants, because that's what it is, a
16 participants test, well, participant plus utility, so
17 that participant plus utility are showing substantial
18 benefits.

19 Now, yes, there are huge cross subsidies
20 coming from people who are not participating, but --
21 but there are four or five, 6.0, I mean it -- what is
22 your feeling about the TRC, do you -- can the TRC be
23 high enough to where you'd say that, you know, you
24 would recommend a program even if the RIM was below
25 one but the TRC was at a certain level?

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1 THE WITNESS: I mean, I -- I agree, you
2 know, I -- in fact, the last case I recommended
3 programs that did not meet the RIM test, that had TRCs
4 in the range of six, and I -- I felt like, you know,
5 this -- this is a -- I fully recognize that you're
6 balancing economics and policy, broad policy, and
7 that, you know, although there's cost effect -- cost
8 effectiveness test, here, that to do any of these
9 programs you're probably going to have to, you know,
10 look -- look beyond RIM, and I -- I think if you get,
11 you know, if you look at the best programs, the ones
12 that get the TRC up in that five or six range, then
13 you know, you're -- you're probably doing the best --
14 the best you can.

15 COMMISSIONER CHRISTIE: It's fine, I just
16 -- what -- what is your commentary on the TRC, then?
17 I mean, we've got a lot of commentary about the T- --
18 TRC, and its validity and what it -- what it shows you
19 or doesn't show you and --

20 THE WITNESS: Well, I mean --

21 COMMISSIONER CHRISTIE: -- if it's low,
22 what -- what is it about if it's a low TRC, meaning
23 one to two, and they picked -- and Dominion said
24 anything over two is good enough, what is your feeling
25 about the TRC that makes you want to, you know,

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1 discount it vis-a-vis RIM, or look for a higher score
2 to get your -- your analysis of the TRC as a -- as a
3 cost benefit test?

4 THE WITNESS: Again, I can't get beyond the
5 -- the rate impact issue. I mean, I -- I hear the
6 theoretical arguments, but I think, you know, bottom
7 line is the customer's going to pay a lot of money, a
8 -- a new rate increase on top of rates that may
9 already be recovering costs fully, and I just don't
10 think you can ignore that, I -- I'd like to ignore it,
11 I'd like to make it go away, that -- you know, that
12 would be the best interest of the customers and -- and
13 in the energy efficiency advocates, but it's -- it's
14 going to be a component, and all these results, if you
15 look at them, make you realize it's -- it's the major
16 component to these programs, it's 70 percent of the
17 cost, what I call cost of these programs.

18 COMMISSIONER CHRISTIE: The lost revenue?

19 THE WITNESS: Lost revenue, and that's if
20 -- that's if rates increase at roughly one and a half
21 to two percent, which is what the Company has assumed
22 in their studies, what happens, you know, if we have
23 what we expect coming down the line with EPA, some big
24 increases, all of that's going to get, I -- I would
25 expect the Company to request all of that, and all of

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1 that becomes part of this -- this, you know, this DSM
2 program.

3 COMMISSIONER JAGDMANN: Mr. Norwood, if
4 your load is increasing do you have lost revenues?

5 THE WITNESS: Well, I mean, that's --
6 that's -- that's the obvious thing that I, you know,
7 question, that, you know, perhaps, and I think maybe
8 some commissions do have a policy of, if you're
9 Trueing-Up lost revenues maybe you look at, you know,
10 did you have revenue growth that offset some of that
11 lost revenue.

12 And I don't know if you have the authority
13 to do that here, but if there was a way to consider
14 increased revenue at -- at the same time you're
15 Trueing-Up lost revenue, then perhaps this issue would
16 become less of a concern.

17 But as it stands now, as proposed, you kind
18 of look at these things in isolation, you have true up
19 proceeding and you look just at the losses and -- and
20 I feel like just -- just reviewing this is going to be
21 very difficult to administer, it'll be like the NR
22 cases as I'm sure you recall, you know, very difficult
23 to really true these things up right.

24 COMMISSIONER CHRISTIE: Okay.

25 COMMISSIONER DIMITRI: Ms. Pierce?

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1 MS. PIERCE: Thank you, Your Honor.

2 BY MS. PIERCE:

3 Q Mr. Norwood, have you had an opportunity to
4 review the other pre-filed testimony in this
5 proceeding, including Dominion's rebuttal testimony?

6 A Yes.

7 Q And do you have any comments on the new
8 issues raised by the Company's rebuttal testimony?

9 A Yes, in my direct testimony I expressed a
10 number of concerns regarding the cost benefit analysis
11 and results supporting Dominion's new proposed DSM
12 programs, and I also expressed concern with the lack
13 of analysis supporting the Company's request for
14 additional funding for existing approved DSM programs
15 and the cost effectiveness of such programs in light
16 of the significant market changes that have occurred
17 since the programs were originally analyzed in 2009.

18 I was hopeful that the Company would update
19 its cost benefit analyses to reflect current market
20 con- -- market conditions and to incorporate a more
21 reasonable study period that was reflective of the
22 measure lives being studied in order to demonstrate
23 that these requests were -- were still justified, but
24 so far no such update has been provided for the new
25 programs.

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1 And in light of this I stand behind my
2 original recommendation that the Commission disallow
3 the requested funding for all new programs proposed by
4 the Company except for the dis- -- distributed
5 generation program.

6 Q Mr. Norwood, did you have an opportunity to
7 review the Commission's staff pre-filed testimony in
8 this case?

9 A Yes, I did.

10 Q And do you have any comments on that
11 testimony?

12 A Yes, I just like to say that, first of all,
13 I think the staff, for what it's worth, I think the
14 staff did a nice job in their analysis. And I do
15 agree that they're recommending approval of -- to
16 commercial programs and energy audit program and the
17 duct testing program, which I think offer reasonable
18 or reasonably high benefits. And I think those are
19 worth looking at if -- if -- you know, I did not
20 recommend them, but -- but I think given the benefit
21 level and particularly on the ener- -- energy audit
22 program, because it has a long life, it has a 25 year
23 life, that the measured benefit for that program is --
24 is probably approaching the level that I -- that I
25 would recommend.

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1 Q Thank you. And did the Company provide
2 updated analysis to support its request for additional
3 funding of existing DSM programs in its rebuttal
4 testimony?

5 A The Company did provide a revised analysis,
6 and this is -- this is attached as schedule four to
7 the rebuttal testimony of Company Witness Newcomb, and
8 based upon my review of this new information, and
9 other information, I recommend that the Company be
10 allowed to recover the additional amount requested for
11 its existing commercial HVAC program, and that amount
12 is presented in rebuttal schedule 46D, statement six,
13 so I do recommend the additional funding for that
14 program.

15 However, I'm unable to determine from the
16 information provided, which was just a schedule,
17 whether the additional funding requested for the
18 commercial lighting program is -- is cost justified.

19 Q Thank you. And just so the record's clear,
20 while recognizing that the RIM test is the only one
21 that the measure -- that measures lost revenues
22 consistent with the Commission's report in the General
23 -- to the General Assembly, in 2009, regarding the
24 cost benefits test and its order in PUE-2009-00081,
25 did you review the results of all four cost benefits

1 tests?

2 A Yes, I have. I think I mentioned that both
3 in the '09 case and in this case we, you know, we
4 looked at the results and certainly I, you know, I
5 considered the RIM test results more heavily for the
6 reasons I've just discussed.

7 Q Okay. One of the concerns expressed in
8 your testimony regards the 25-year study period used
9 by the Company, through discovery did you request that
10 the Company provide the cost benefit analysis using a
11 15-year study period?

12 A Yes, we did, and we -- we were not able to
13 get that information.

14 Q Do you agree with the Company that using a
15 fif- -- excuse me, a 25-year period for this DSM file
16 is more appropriate than using a 15-year analysis?

17 A No, I think -- I think I've explained, and
18 we can talk about this a little bit later in the
19 confidential section, but the bulk of these programs
20 being proposed and requested here are -- have lives
21 that are well below 15 years, even. There's only one
22 program, I believe, that's -- that has a measure life
23 of up to 25 years.

24 And so the concept of doing a study, an
25 analysis out 25 years on programs whose lives, you

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1 know, are 15 years and less makes -- makes little
2 sense to me, and I -- and I think if you look at the
3 results of the schedule two which is attached to my
4 testimony and we'll look at that here in a little bit
5 I think, the -- you can see that up until 15 years
6 it's almost a -- a loss in every year or -- or no
7 benefit, whatever you want to call that, but the
8 programs cost more than they're saving.

9 And then beyond that, in out years, beyond
10 15 years, when market prices are forecasted to go up
11 higher you start seeing some offsetting benefit. And
12 my view is trying to kind of bootstrap that back into
13 a study of a measure that may only be seven years or
14 ten years is not -- is not appropriate.

15 Q And a few minutes ago you mentioned the
16 lost revenue amount of 330 million dollars, can you
17 con- -- tell us where that figure came from, where you
18 -- where you got that figure?

19 A Yes, that -- again, that was from the staff
20 RFI 1-2.

21 Q Thank you. And is that 330 million dollars
22 of lost revenues, is that a capped amount?

23 A No, no, again I -- and I -- I think I
24 touched over this as we were --

25 Q Right?

1 A -- talking, but that amount, as I
2 understand it, is subject to true up, and what --
3 whatever the lost revenue ultimately ends up being,
4 you know, is a revenue based upon what a future rate
5 might be, and that -- that's what they will seek to
6 recover.

7 Q Thank you. Now, Company Witness Barker
8 states that it would be shortsighted to reevaluate the
9 Company's DSM programs to reflect current market
10 energy prices because this ignores the important hedge
11 value that DSM programs provide against future market
12 energy price increases; do you agree with that?

13 A No. I think I note in my testimony that
14 Commission and its order from the 2009 case made it
15 clear that it expected the Company to continuously
16 evaluate programs that are -- that are proved. And,
17 you know, I view that to be, you know, really basic
18 commonsense, because these programs, you know, if you
19 think about them they're not -- they're not like
20 you're going out and investing in a power plant and
21 you have a bunch of sunk costs and then after that you
22 have very little control over the cost of that
23 endeavor if market changes.

24 Now, here we're talking about programs that
25 are entirely expenses, very little capital at all, and

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1 so -- and they're also short lead time to achieve the
2 results we're talking about, so you know, in my view,
3 particularly if there's a major change in the market
4 in the near term, the Company ought to be assessing
5 that in their reports on the programs. They ought to
6 be addressing that, you know, not just the kilowatt
7 hour savings but what's actually being achieved in
8 terms of benefits and adjust -- adjusting program
9 expenditures, you know, as needed.

10 You know, the second issue on whether these
11 programs represent an important hedge? Well, you
12 know, I think at the cost level they're at they
13 certainly don't represent, in my view, much of a
14 hedge. And we're really not talking about a lot of
15 energy, here, in the long run. Certainly at this
16 juncture, probably a less -- less than a percent of
17 the Company's supply will be reduced by this energy
18 over the next five years.

19 And so, you know, that -- that -- that's
20 not really an important hedge, that's -- that's --
21 certainly I don't want to diminish the potential
22 benefits of it, but it's not something that you would
23 do and, you know, normally call a -- a hedging
24 program.

25 COMMISSIONER DIMITRI: Mr. Norwood, let me

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1 ask you, in your testimony you -- in -- in your
2 pre-filed testimony, you indicate that the Company's
3 analysis, in your words, indicates there will be
4 little or no customer benefits from proposed DSM
5 programs over the next 15 years.

6 THE WITNESS: Right.

7 COMMISSIONER DIMITRI: Well, how -- how
8 does -- and I'd like to hear more about that, maybe --
9 maybe in -- in --

10 THE WITNESS: Yes.

11 COMMISSIONER DIMITRI: -- the confidential
12 session, but how do you square that with your
13 statement that they ought to be looking at this each
14 year to determine the benefits?

15 THE WITNESS: I guess implied in my
16 statement is it's a proved program. There's a program
17 that actually has benefits. But what I'm saying, once
18 approved, and that's because you've decided, you know,
19 it's in the public interest, you know, best example is
20 '09 programs, which I thought were good and
21 recommended, and -- and we all thought were good, and
22 -- and now we've got instead of \$9 gas, which is what
23 we were thinking back then, we've got \$3 gas.

24 And so to me that's -- those are material
25 changes that we need to think about before we continue

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1 to just pour money into the hole to achieve more
2 losses, that's my -- my view, that if this was a -- if
3 you had built a power plant and they went out and sunk
4 -- sunk much money in the power plant, well, then you
5 could do little about it, you know, you could dispatch
6 it down, but you could do little about that initial
7 investment.

8 But here we're talking about ongoing
9 program costs that have some control to them, they can
10 ramp them down, they can terminate them, you know, and
11 defer them for a period. And all I'm saying is I
12 think that's a reasonable expectation.

13 COMMISSIONER DIMITRI: Okay.

14 BY MS. PIERCE:

15 Q Company Witness Barker also discusses the
16 Company's proposal to withdraw its requests to collect
17 projected lost revenues for its residential lighting
18 programs in his rebuttal testimony.

19 Does this new pro- -- proposal alleviate
20 your concerns regarding the cost effectiveness of the
21 pros -- programs?

22 A Well, I -- you know, I certainly commend
23 the -- the offer to pull down a portion of the
24 projected lost revenue recovery, but I think what the
25 Company is saying is, you know, we're still going to

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1 true this up to whatever it is, and the fact of the
2 matter is, if you look at the results on the -- the
3 lighting programs, they're just not cost effective now
4 under current conditions when you include lost
5 revenues.

6 So you know, if it's just a matter of we're
7 pushing this recovery off for two or three years until
8 we can do a true up, I don't think that improves the
9 economics of this program, so it would not change my
10 recommendation.

11 Q Thank you. And do you agree with witness
12 Barker that the Commission should approve the DSM
13 programs proposed in this case because they are --
14 because there are not many residential DSM programs
15 that will pass the RIM test?

16 A Well, I -- I do agree that this is -- this
17 is a legitimate concern, that there -- there really
18 are not that many residential programs you can look at
19 that are going to achieve a RIM -- RIM test score of
20 1.0, and certainly not when you've got three dollar
21 gas.

22 And -- but my -- my judgment is that you
23 have a goal, or there is a goal in this state to
24 achieve a certain savings level by 2022, and these
25 programs can be ramped up fairly quickly, you're -- in

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1 my judgment there's no urgency to do a residential
2 program just to do a program now, particularly if it's
3 losing money.

4 There are many potential rate increases
5 coming down the line, and if market prices do increase
6 we may want to look again at this program, and we
7 might want to approve it later, and -- and you could
8 still do that and achieve the 2022 goal.

9 And I think would be beneficial to all to,
10 you know, particularly on these programs that look
11 very marginal right now, to -- to wait and -- and --
12 until they become more economic.

13 MS. PIERCE: Thank you, Mr. Norwood. Your
14 Honor, my remaining questions for Mr. Norwood deal
15 with the confidential information.

16 COMMISSIONER DIMITRI: All right. Well, at
17 this time anyone who has not signed a confidentiality
18 agreement, we'd ask that you leave the courtroom. I
19 will ask the bailiff to suspend the webcast at this
20 point.

21 (Whereupon, the proceedings continued as
22 confidential.)

23
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25

1 (Confidential portions of Mr. D. Scott
2 Norwood's testimony can be found under separate binder
3 and run from page 487 to 564.)

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1 (Whereupon, the proceedings continued as
2 public.)

3 COMMISSIONER DIMITRI: Appears we're back
4 on the web and public sessions? And you have sur
5 rebuttal for Mr. Norwood.

6 MS. PIERCE: No, Your Honor, I will have
7 redirect for Mr. Norwood, but I thought we would
8 finish the cross-examination and then I would just do
9 that in one -- one round.

10 COMMISSIONER DIMITRI: Right.

11 MS. PIERCE: Thank you.

12 COMMISSIONER DIMITRI: Mr. Jaffe, I believe
13 that's you.

14 MR. JAFFE: Thank you, Your Honor.

15 CROSS-EXAMINATION

16 BY MR. JAFFE:

17 Q Hello, Mr. Norwood.

18 A Hello.

19 Q I'd like to -- to start just with some --
20 some introductory questions. You mentioned on page
21 one of your testimony, lines nine and ten, that you're
22 a -- an energy consultant in the areas of electric
23 utility regulation, resource planning, and energy
24 procurement; is that right?

25 A That's right.

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1 Q And on the next page, page two, towards the
2 bottom, lines 19 and 20, you mentioned that you've
3 testified in proceedings involving base rate, fuel,
4 and -- in power plant certification matters before
5 state regulatory commissions; is that right?

6 A That's correct.

7 Q Now, you don't mention here, and I didn't
8 catch any in your attached resumé, any experience in
9 testing in DSM or energy efficiency portfolio approval
10 proceedings like this one other than this one, and of
11 course, the 2009 Dominion case?

12 A Yeah, proceedings just like this, those are
13 probably the only two.

14 Q So there -- so there are no other
15 jurisdictions where you've provided testimony on -- on
16 specific DSM programs; is that right?

17 A Well, I'm -- I have reviewed DSM programs
18 in conjunction with IRP cases, but cases like this,
19 where there's cost recovery being proposed, I have not
20 participated in other than the two -- these two cases
21 in Virginia.

22 Q I'd like to pass out a document, if I
23 might. Do you have the -- the document that's been
24 passed out in front of you, Mr. Norwood?

25 A Yes, uh-huh.

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1 Q All right. And this is the Attorney
2 General's response to the Company's first set of
3 interrogatories, question two; is that correct?

4 A Right.

5 Q And do you recognize this answer?

6 A Yes.

7 Q And this is your answer to that question,
8 is that right?

9 A Yes.

10 Q I'd like to have this document marked and
11 move its admission?

12 COMMISSIONER DIMITRI: It will be marked as
13 Exhibit 26. Any objection to admission? Hearing
14 none, it's admitted.

15 (Exhibit No. 26 was marked for
16 identification and received into evidence.)

17 BY MR. JAFFE:

18 Q And on this exhibit you are asked by the
19 Company to identify the regulatory commission's and
20 agencies where you've addressed issues relating to DSM
21 programs?

22 A That's correct.

23 Q And if we can scroll through, I believe you
24 highlighted in the attachment, those -- those dockets,
25 and the first one item, it's number 70 on the list, is

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1 a -- a case here, is in fact the IDCC power plant
2 proposal from Appco; is that right?

3 A Right.

4 Q So there were -- there were no DSM programs
5 at issue in that docket; is that right?

6 A Yeah, I think this must have been a -- a
7 carryover of a response I provided in another
8 response, because that one, IDCC case, the Biomass
9 case on the next page, item 104, item 112, Biomass,
10 113, LSR wind generation projects were not DSM
11 projects.

12 Q And then the only two other highlighted
13 items are the current case that we're in?

14 A That's correct.

15 Q And the 2009 DSM case?

16 A That's correct.

17 Q All right. So then it's fair to say
18 compared to, you know, Mr. Pickles, who testified he's
19 got 25 years of experience, specifically E- -- in EM
20 and V and DSM programs at ICF, or Mr. Pettit, who's
21 got extensive experience, specifically in DSM at KEMA,
22 or Mr. Powell, who since 1981, has developed his
23 expertise specifically on energy efficiency resources
24 and DSM resources, or Mr. Loiter, who is with Optimal
25 Energy, a firm that is specifically focused on energy

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1 efficiency consultancy, you wouldn't consider yourself
2 as being a -- having a specialized expertise in -- in
3 DSM or EM and V or energy efficiency proposals, you --
4 you would be more of a general expertise in electric
5 utility regulation; is that right?

6 A Yeah, I think, you know, resource planning
7 and economics would be the -- the expertise I bring to
8 this proceeding. And, you know, I'm not challenged a
9 specific design elements, for example, of the DSM
10 programs proposed in the case, but focused on the
11 economics and how those are calculated.

12 Q Let me move on, if I might, to talk about
13 some of those sort of economic factors, that --

14 A All right.

15 Q -- you might have more of an expertise in.
16 You talked on page 19 of your testimony about, you
17 raise the issue of Carbon pricing?

18 A Yes.

19 Q And you said, Dominion did not evaluate --
20 also did not evaluate the potential for Carbon
21 regulations implemented at lower price levels or at a
22 later date than was assumed in the Company's base case
23 analysis; is that right?

24 A That's correct.

25 Q And in Carbon regulation might be

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1 characterized as an environmental compliance cost that
2 could drive up the cost of the supply-side resources;
3 is that right?

4 A Yes.

5 Q And your concern, I take it, is that the
6 Company overestimated this particular cost; is that
7 right?

8 A Well, my concern is they didn't look at a
9 sensitivity to assess the -- the effects of potential
10 different future outcomes on Carbon on these DSM
11 program costs and benefits, primarily savings
12 estimates on DSM.

13 Q Although they did run a -- a no-carbon
14 scenario; is that right?

15 A I believe in response to discovery they ran
16 a no-carbon scenario for staff, on staff's request,
17 and they did run a 25 percent lower fuel price
18 sensitivity, but -- but not a no-carbon in their
19 initial filing.

20 Q So I think we've established that
21 environmental compliance costs, like Carbon
22 regulation, could effect energy market prices.

23 I assume you'd agree that there might be
24 other environmental compliance costs that would effect
25 market prices; is that correct?

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1 A Yes.

2 Q And so you're aware -- are you aware of a
3 series of -- of EPA regulations related to the energy
4 sector, particularly the final Mercury and air toxics
5 rule, which has been published in the Federal register
6 as of February 16th of this year, a proposed coal
7 combustion residual rules, regulating coal ash from
8 power plants which has also been published as a
9 proposed rule in the Federal register, an EPA proposed
10 rule under Section 316B of the Clean Water Act to
11 require best technology for cooling water, intake
12 structures on existing power plants, that one also
13 published in the Federal register, these are just
14 three examples, but you would agree that these are the
15 kinds of examples that might -- would increase
16 supply-side cost; is that right?

17 A Absolutely, yeah.

18 Q And yet the Company has not, to your
19 knowledge, included these costs in its cost and its
20 analysis?

21 A I have not looked at the IRP to see what
22 they assumed there, but some of these new regs I don't
23 think would be -- well, let me just say I don't know
24 what they did in the IRP.

25 Q Well, specifically for this docket, in

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1 terms of conducting the cost benefit test analyses for
2 the DSM programs at issue here, they didn't factor
3 these in, to your knowledge?

4 A Well, the modeling was conducted in
5 conjunction with the IRP, yes, the 2011 IRP. So I
6 don't -- I did not see a separate and apart from that
7 analysis of different regu- -- regulations, if that's
8 what you're suggesting.

9 Q So you didn't see --

10 A I haven't seen -- I haven't seen that in
11 discovery.

12 Q You have no reason to believe that they've
13 conducted this, you haven't seen anything to suggest
14 that they conducted these analysis on these --

15 A Yeah, again, I don't know, again, with the
16 caveat, I don't know what they did in the IRP, but
17 some of the new regs they would not have known of in
18 the IRP.

19 Q So these -- these regs that we can see from
20 what you've seen haven't been factored in or at least
21 you don't know of them having been factored in?

22 A Well, they're proposed regs right now, for
23 the most part, and -- and it's difficult to model
24 proposals.

25 Q Well, you would ag- -- are you aware that

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1 the -- the Mercury and toxic rule is a final rule?

2 A Yes.

3 Q But you didn't criticize the Company for
4 failing to include these costs in its analysis, did
5 you?

6 A I don't think I did.

7 Q And if -- if the Company had included these
8 kinds of costs, or more of these kinds of costs, that
9 would make the DSM portfolio look even better on the
10 cost benefit analysis, wouldn't it?

11 A It could to the effect that -- to the
12 extent that affected the marginal cost.

13 Q And you just said that these regs wouldn't
14 cause the supply cost -- supply-side cost to increase;
15 is that right?

16 A They -- they would increase supply-side
17 cost, I'm not sure how much they would be reflected in
18 the margin, but I -- I would expect they would overall
19 increase power costs.

20 Q And then, just to make sure we're in
21 agreement on this, and the DSM program analysis, then,
22 would look better by comparison?

23 A Yes, anything that increases the power cost
24 should improve the DSM economics.

25 Q All right. Moving on to --

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1 COMMISSIONER JAGDMANN: If I can just -- if
2 I can just ask, would that in- -- increase your lost
3 revenues or would that be in your --

4 THE WITNESS: Yeah, you're right, it would
5 be there, so there might be -- there would definitely
6 be offsetting cost. I'm -- I'm not sure how that
7 would -- you really have to look at what was required
8 and whether it triggered retirements, in which case if
9 you had to retire, you have to replace. And so it
10 could be -- it could be sort of a wash. But it would
11 definitely or should increase market energy prices,
12 and it probably would have an increase on lost
13 revenues.

14 BY MR. JAFFE:

15 Q All right. Well, let's take a look at page
16 nine. You bring up the example of the Biomass cases?

17 A Yes.

18 Q And your calculation was that those were a
19 -- the proposed programs in this case were, by your
20 count, 198 million dollars over five years, level of
21 expenditure, approximately equal to the capital cost
22 of the Biomass conversion; is that right?

23 A Excluding the lost revenues which adds
24 about another 330 million.

25 Q Now, as far as new energy being added to

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1 the grid, those Biomass conversions, and you were
2 involved in that docket, the only issue is whether the
3 fuel switch from coal to Biomass would increase the
4 capacity factors for Biomass; is that right, in other
5 words, there -- there wasn't any proposal for putting
6 new generation capacity on the market -- on -- on the
7 grid through those programs?

8 A That's right.

9 Q And you said the -- the lost revenues
10 calculation isn't a -- a part of your analysis there,
11 the other thing that's -- that's not in the -- on the
12 power plant side, here, the operating cost for those
13 power plants, after those conversions are complete,
14 those costs aren't factored into that 198 million
15 dollars, we're just talking capital costs?

16 A Yes, this is the investment cost for the
17 Biomass plans. And I was just trying to give context
18 to, you know, what we're talking about dollars wise to
19 a -- a recent proceeding.

20 Q Sure. And if we factor in, in addition to
21 operating costs, things like transmission distribution
22 costs, those are -- those -- that also is not in the
23 198 million dollars for the Biomass case; is that
24 right?

25 A That's right.

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1 Q All right. So in short there are -- there
2 are a lot of costs that don't appear in the
3 construction costs for those Biomass conversions that
4 -- that might be relevant to sort of making an apples
5 to apples comparison to the DSM portfolio; is that
6 right?

7 A Yeah, I mean, they -- they wouldn't add up
8 to 500 million, but there are other costs there and --
9 and my point was not to say they were comparable, it's
10 just to give you a -- a point of reference of how many
11 dollars we're talking about.

12 Q Now, referencing the -- the 500 million
13 dollar number, and that was your calculation based on
14 lost revenues combined with the cost of the programs
15 over five years; is that right?

16 A Yes, that's based upon the Company's
17 projection of lost revenues over the five-year term
18 proposed in this case.

19 Q And -- and you testified that you
20 calculated that as delivering 3.7 million megawatt
21 hours; is that right? I think that's what I heard you
22 say a few minutes ago?

23 A That's a -- I guess that's the number from
24 Mr. Newcomb's testimony. He has an exhibit that shows
25 the projected megawatt hour savings, so yes.

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1 Q And so to get that 3.7 number, are you just
2 adding up the first five years?

3 A Yes.

4 Q Only?

5 A Yes.

6 Q But of course you understand that the
7 program benefits would extend for the full life
8 measures of the program?

9 A That's right.

10 Q So that 3.7 million megawatt hours, that's
11 only the first five years essentially through the ramp
12 up period?

13 A That's right.

14 Q And in fact, if you look at the rest of
15 Mr. Newcomb's testimony in that point, he points out
16 that by 2026 we're up to 816,000 megawatt hours for
17 that one year, plus cumulative, you add up all the
18 years before, you're getting to a number significantly
19 larger than 3.7?

20 A Yeah, and what you'd have to do, if you
21 wanted to calculate it over 15 years or 25 years, what
22 you'd have to do is to add up the lost revenues and
23 the program cost and the -- the projected gigawatt
24 hour savings over that period. And -- and you could
25 do that for any period you wished.

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January 17, 2012

VIA ELECTRONIC FILING

The Honorable Joel H. Peck
Office of the Clerk, State Corporation Commission
c/o Document Control Center
P.O. Box 2118
Richmond, VA 23218-2118

RE: Application of Virginia Electric and Power Company for approval to implement new demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia

Case No. PUE-2011-00093

Dear Mr. Peck:

Enclosed for filing in the above-captioned matter are the pre-filed direct testimony and exhibit of Jeffrey Loiter on behalf of Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of the Sierra Club ("Environmental Respondents").

Should you have any questions regarding this filing, please contact me at (434) 977-4090. Thank you for your assistance.

Sincerely,



Caleb A. Jaffe, Southern Environmental Law Center

cc: Commission Staff and Service List

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00093
January 17, 2012*

**TESTIMONY
OF
JEFFREY LOITER**

**ON BEHALF OF
THE CHESAPEAKE CLIMATE ACTION NETWORK, APPALACHIAN VOICES, AND
THE VIRGINIA CHAPTER OF THE SIERRA CLUB
("ENVIRONMENTAL RESPONDENTS")**

**Virginia State Corporation Commission
Case No. PUE-2011-00093**

JANUARY 17, 2012

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00093
January 17, 2012*

1 **Q. Please state your name and business address.**

2 A. My name is Jeffrey Loiter and my business address is Optimal Energy, Incorporated, 14
3 School Street, Bristol, VT 05443.

4 **Q. On whose behalf are you testifying?**

5 A. I am testifying on behalf of the Chesapeake Climate Action Network, Appalachian
6 Voices, and the Virginia Chapter of the Sierra Club (collectively, “Environmental
7 Respondents”).

8 **Q. Mr. Loiter, by whom are you employed and in what capacity?**

9 A. I employed as a Managing Consultant by Optimal Energy, Inc, a consultancy specializing
10 in energy efficiency and utility planning. In this capacity, I direct and perform analyses,
11 author reports and presentations, manage staff, and interact with clients to serve their
12 consulting needs. My clients include utilities, NGOs, state energy offices and efficiency
13 councils, and third-party program administrators. For example, I provide Orange &
14 Rockland Utilities with consulting services on program design and implementation and
15 participate on the consultant team supporting the work of the Massachusetts Energy
16 Efficiency Advisory Council.

17 **Q. Please summarize your work experience and educational background.**

18 A. I have 15 years of experience in environmental and economic consulting. For the
19 past 5 years, I have been engaged in a variety of work at Optimal Energy related to
20 energy efficiency program design and analysis. For example, I prepared two documents
21 for inclusion with EPA’s *National Action Plan for Energy Efficiency*: a guidebook on

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00093
January 17, 2012*

1 conducting efficiency potential studies, and a handbook describing the funding and
2 administration of clean energy funds.¹

3 In my capacity as a Managing Consultant at Optimal, I also advise clients on
4 efficiency program design and implementation. For example, I recently contributed to a
5 5-year Energy Efficiency and Demand Response Plan for the Tennessee Valley
6 Authority. I have also participated in several studies of efficiency potential and
7 economics, including ones in New York, Vermont, Texas, Massachusetts, and Prince
8 Edward Island. These studies have ranged from macro-level assessments to extremely
9 detailed, bottom-up assessments evaluating thousands of energy efficiency measures
10 among numerous market segments.

11 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
12 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
13 Environmental Engineering from Cornell University and an *M.S.* in Technology and
14 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
15 ER-JML-1.

16 **Q. Have you previously testified before the Virginia State Corporation Commission**
17 **(“the Commission” or “SCC”)?**

18 **A.** Yes, I testified on behalf of the Southern Environmental Law Center, Virginia
19 Chapter of the Sierra Club and Appalachian Voices in case no. PUE-2009-00023.

20 **Q: What is the purpose of your testimony?**

¹ These documents can be found at http://www.epa.gov/cleanenergy/documents/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

1 A: The purpose of my testimony is to present the conclusions of my review of
2 Dominion's application and testimony filed in this docket. Specifically, I focus on the
3 proposed demand side management programs for which Dominion seeks approval, the
4 proposed increase in spending caps for two existing commercial programs, and the use of
5 cost-effectiveness tests. Based on my analysis, I find that Dominion's proposed programs
6 represent typical approaches that have been implemented in other jurisdictions by utilities
7 and other program administrators, yet could be improved in a number of ways. Based
8 solely on my review of the publicly-available information in the filing, I conclude that
9 there are no critical deficiencies with these programs, with the exception of the
10 Commercial Distributed Generation program.

11 **Q: How is your testimony organized?**

12 A: My testimony is organized into the following four sections:

- 13 1. Summary of Recommendations
- 14 2. Company's Proposed Programs
- 15 3. Request to Increase Spending Caps for Two Existing Commercial Programs
- 16 4. Cost-Effectiveness Tests

17 **Q: Are you submitting exhibits along with your testimony?**

18 A: Yes. My testimony includes the following exhibit:

- 19 • Exhibit ER-JML-1 – Resume of Jeffrey Loiter

20 **Q: In preparing your testimony, have you relied on any information characterized by**
21 **the Company as "Extraordinarily Sensitive?"**

22 A: No.

1 **Q: Why not?**

2 A: Because of a late-arising dispute with the Company on access to these materials.
3 Therefore, I have relied solely on the publicly-available material in the filing and
4 supporting materials.

5 **Q: What effect does relying solely on publicly-available materials have on your
6 testimony and your recommendations?**

7 A: Without access to the material label “Extraordinarily Sensitive” by the Company,
8 I cannot offer stronger support for the approval of the filed programs. For example, I am
9 unable to review and comment on the level of program spending allocated to
10 administrative functions or payments to implementation contractors in comparison to that
11 allocated for payments to customers as incentives. I am also unable to review the
12 assumptions and data used in the cost-effectiveness testing to assess their appropriateness
13 and how they compare with assumptions made by other utilities and jurisdictions in
14 applying these tests. These are just two examples; the Company marked a very large
15 amount of information “Extraordinarily Sensitive.”

16 **Q: In your experience, is the amount of information and data marked “Extraordinarily
17 Sensitive” by the Company similar to that given such treatment in other cases in
18 which you have been involved?**

19 A: No, the quantity far exceeds what I have seen elsewhere. Furthermore, I do not
20 recall ever participating in a case with the level of protection asserted by the Company,
21 such as with the “Extraordinarily Sensitive” information in this case.

1 **Q: Can you provide an example of cases in which similar information that has been**
2 **protected by the Company was more readily available?**

3 A: Certainly. As just one example, in 2008 and 2009, I provided support to the
4 Maryland Energy Administration in their review of DSM plans filed by utilities in that
5 state. In those filings, the following types of information that the Company has protected
6 in this case was included in the publicly-available filings: EM&V budgets; projected
7 program costs including cost breakout for administration, incentives, marketing, and
8 other spending categories; actual modeled costs and benefits of each program; detailed
9 cost and benefit information for each measure; and avoided cost assumptions used in the
10 benefits calculations, including forecast energy and capacity prices. In other cases, some
11 of these materials, particularly those related to forecast energy and capacity prices, have
12 been marked as “Confidential.” In those cases, the filing utility has never objected to my
13 access to those materials, subject to typical protections on further disclosure of their
14 contents.

15 **Part One: Summary of Recommendations**

16 **Q: Please summarize your conclusions and recommendations based on your review of**
17 **Dominion’s application and testimony?**

18 • I support the Company’s request for flexibility in spending between programs
19 within sectors and with respect to any overall spending cap. Furthermore, I
20 recommend that the Commission allow additional flexibility in setting
21 incentive levels and other program implementation details.

- 1 • I recommend that the Company broaden the proposed Residential and
2 Commercial Energy Audits to more comprehensively identify and support
3 efficiency upgrades, and further than these programs be better integrated with
4 the many other measures and programs offered by the Company.
- 5 • I recommend that the proposed Residential Bundle programs related to heat
6 pump be extended to central air conditioning systems.
- 7 • I support the Company's request for additional funding for the existing
8 Commercial Lighting and HVAC Program, but recommend some changes to
9 the measures included in those programs.
- 10 • I recommend that the Commission not reject programs with RIM test scores of
11 less than 1.0 solely on the basis of a TRC between 1.0 and 2.0.

12 **Part Two: The Company's Proposed Programs**

13 **Q: Please describe the Company's proposed suite of programs?**

14 **A:** The Company proposes five programs that I view as pure energy efficiency programs:
15 Commercial Energy Audit
16 Commercial Duct Testing & Sealing
17 Commercial Refrigeration
18 Residential Lighting Phase II
19 Residential Bundle Program, composed of Home Energy Check-Up, Duct Testing and
20 Sealing, Heat Pump Tune-up, and Heat Pump Upgrade measures.

21 In addition, the company claims an additional proposed program, Commercial Distributed
22 Generation, as both an energy efficiency program and a demand response program.

1 **Q: Why do you draw a distinction between the Commercial Distributed Generation**
2 **program and the other programs in this filing?**

3 A: Because, in contrast to Company Witness Barker, I do not believe that this program
4 qualifies as an efficiency program as that term is defined in Va. Code § 56-576. I have
5 reviewed the definition of “energy efficiency program” and note that a demand response
6 program qualifies as energy efficiency if it is “designed to reduce electricity consumption
7 so long as [it] reduce[s] the total amount of electricity that is required for the same
8 process or activity.” The Commercial Distributed Generation program, as proposed by
9 the Company, clearly does not meet this definition. It merely shifts generation from the
10 Company to the customer’s site. The customer still requires the same amount of
11 electricity as before program implementation. The only potential savings from this
12 activity are in reduced transmission and distribution losses during on peak periods.

13 **Q: If there are savings from reduced transmission and distribution losses, would this**
14 **program qualify as an efficiency program?**

15 A: The data submitted by the Company do not clearly explain whether or not the projected
16 energy savings from this program are the total amount of energy shifted to customer
17 generation or limited to merely the avoided transmission and distribution losses. If the
18 latter, and further if this program meets cost-effectiveness criteria assuming *only* these
19 avoided losses contribute to system benefits, then it seems the Commission could
20 evaluate the program as energy efficiency and approve or disapprove of the program on
21 its other merits, including whether or not reducing transmission and distribution losses

1 can be considered to reduce the total amount of electricity consumed (rather than
2 generated) for a process or activity.

3 **Q: Do the other proposed programs meet the definition of energy efficiency program as**
4 **per the Virginia code?**

5 A: Yes, I believe they do.

6 **Q: How do these proposed programs compare with the Company's previously filed and**
7 **approved efficiency programs?**

8 A: The newly-filed programs represent important expansions of the Company's overall
9 DSM portfolio to additional end-uses and measures. This will present customers with a
10 broader range of opportunities for money-saving efficiency investments and increase the
11 number of customers who participate in the efficiency programs. In addition, the
12 additional savings projected to result from the filed programs will contribute towards
13 achievement of the Commonwealth's efficiency goals.² I believe, though, that
14 achievement of those goals will require even greater investments in efficiency and more
15 participation by the Company's customers.

16 **Q: Is greater investment in efficiency investments and more participation in efficiency**
17 **programs something the Commission should support?**

18 A: Yes, efficiency is the least-cost resource available to Dominion to meet its load
19 requirements. For example, the Company's recently filed IRP found that a portfolio of
20 approved and proposed DSM programs were selected by the optimization model in all

² In 2007, the Virginia General Assembly established an energy savings goal of "reducing the consumption of electric energy by retail customers...by an amount equal to 10% of the amount of electric energy consumed by retail customers in 2006." See Enactment Clause 3, Chapter 888, Va. Acts of Assembly (2007).

1 cases, indicating that it served load less-expensively than other supply options. By
2 deferring the need for additional supply, DSM helps moderate rates in the long-term.

3 For customers, efficiency investments result in lower energy bills and represent
4 an excellent return on investment. Customers care about the services they get from
5 electricity, rather than consuming electricity. They want hot showers, a comfortable home
6 or workplace, lower production costs, and cold sodas for as little energy cost as possible.
7 Efficiency programs help them accomplish these goals.

8 For the citizens of Virginia, efficiency investments result in reduced emissions
9 from power generation and economic savings. In addition, a study published by the
10 Southeast Energy Efficiency Alliance found that a package of energy efficiency policies,
11 if enacted in Virginia, would result in a net increase of nearly 30,000 jobs by 2020.³

12 **Q: Is greater investment and participation in the Company's efficiency programs**
13 **necessary for Virginia to meet its efficiency goals?**

14 **A:** Yes, The Company represents a large portion of the Commonwealth's electric
15 load, approximately 68%.⁴ According to the current filing, the savings from the
16 previously approved and currently proposed programs will achieve, over a period of 7
17 years, just one-sixth of this goal, or less than 2% savings. Achieving the entire 10% goal
18 by 2022 will therefore require substantial additional program spending by the Company.
19 As I stated in my testimony in PUE-2009-00023, this energy savings goal can be
20 realistically accomplished; it is far below the cost-effective savings levels that have been
21 estimated to exist in Virginia and other states and is not overly aggressive. Commissions

³ *Energy Efficiency in the South*, M.A. Brown, et al, published by Southeast Energy Efficiency Alliance, April 2010.
http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

⁴ From <http://www.eia.gov/electricity/data.cfm#sales>. Accessed 12 January 2012.

1 elsewhere have supported this level of savings and spending necessary to acquire it,
2 because this spending typically generates economic benefits at least double the level of
3 program expenditure. I also note that both the Commission and the Company have
4 expressed support for the 10% energy savings goal set by the General Assembly. The
5 Commission's report in PUE-2009-00023 states that it did not receive any evidence
6 demonstrating that the 10% savings goal is unrealistic or unachievable.

7 **Q: Can Dominion cost-effectively achieve greater levels of participation and energy**
8 **savings than what it projects from the proposed programs?**

9 A: Certainly. The proposed efficiency programs, along with the previously approved
10 programs, represent a portfolio with reasonably good coverage of end-uses and markets.
11 Residential measures and end-uses covered include lighting and HVAC systems, while
12 commercial customers can access rebates for lighting, cooling, and refrigeration
13 measures. Nevertheless, together they only achieve 17% of the efficiency goal. I believe
14 that these programs and the previously approved programs, implemented using best
15 practices from other jurisdictions and recognizing the long history of DSM programs in
16 this country, are sufficient to achieve the goal if given the budget to do so.

17 **Q: Is there some flaw in the Company's proposed programs that limits their ability to**
18 **achieve greater savings?**

19 A: While I do have several recommendations for improvements to the individual
20 programs, it seems that the primary reason why the previously approved and proposed
21 programs do not attempt to achieve a greater portion of the 10% goal is the Company's
22 assertion that they will reach "market saturation" within five years (see, for example,

1 Witness Newcomb, Schedule 3, page 2 of 19). The Company claims that the proposed
2 penetration rates are the maximum that could be achieved given the incentive levels
3 proposed.

4 **Q: Are greater participation levels are feasible?**

5 A: Yes. Customer participation is a function of many factors, only one of which is
6 the magnitude of a financial incentive. Still, incentive payments are one of the primary
7 motivating features of many program designs. Greater incentives, all else equal, will lead
8 to greater levels of participation. I do not believe that the current incentive levels and
9 assumed penetration rates represent full saturation of the market for efficiency measures.
10 For example, the Commercial Duct Testing and Sealing Program is forecast to reach
11 about 2,100 customers over 5 years of program implementation (Witness Newcomb,
12 Schedule 5). According to the Company's response to Staff Interrogatory 7-55,
13 approximately 218,000 customers will be eligible for this program. Therefore, the
14 cumulative 5-year participation in this program represents just 1 percent of the total
15 market. The Commercial Energy Audit Program has slightly more participation, reaching
16 almost 2,700 customers, but is, presumably, applicable to an even larger number of
17 commercial customers. By any measure, it is feasible to reach more than 1 percent of the
18 Company's existing customers over 5 years. The naturally-occurring rate of efficiency
19 investment is likely to be far greater than this.

20 **Q: Should the Company therefore increase its incentive payments?**

21 A: Potentially. It can be difficult to determine *a priori* the incentive levels that will
22 generate the desired rate of program participation, particularly in jurisdictions with

1 limited experience of efficiency programs. For this reason, the flexibility to adjust
2 incentives and other program offerings in the facing of changing customer behavior and
3 market conditions is an important characteristic of high-performing programs.

4 **Q: The Company has requested some flexibility from the Commission with respect to**
5 **spending caps and the distribution of funding across programs. Do you support this**
6 **request.**

7 A: Yes, very much so. Existing technologies improve over time and new
8 technologies enter the market, the price of higher efficiency technologies declines,
9 markets become more accepting of new technologies and services, and changes in
10 ancillary technologies and markets affect the market for energy-consuming equipment.
11 Therefore, program administrators should be given flexibility in program implementation
12 to respond to these changes without having to return to the Commission for approval.
13 Typically, flexibility is allowed in setting incentive levels, setting qualifying efficiency
14 criteria, adding or removing measures from prescriptive rebate programs, and other
15 implementation strategies. Therefore, I support the Company's request for flexibility
16 (Petition, p. 9, paragraph 13), in spending within each sector, plus or minus 5 percent of
17 total budget. Furthermore, I recommend that the Commission to consider allowing
18 additional flexibility within programs such as incentive levels and other factors, as noted
19 above.

20 **Q: Are increased incentive payments sufficient to increase participation to the level**
21 **where the 10% goal would be achieved?**

1 A: No. That would imply that customer participation in efficiency programs is solely
2 a function of the monetary incentive provided. Years of experience with efficiency
3 programs tell us that this is not true. While the increased first cost of higher efficiency
4 equipment is a real hurdle that incentives can overcome, it is but one of several barriers
5 that must be cleared to promote successful efficiency investment and achieve high energy
6 savings levels from efficiency programs.

7 **Q: Please explain what you mean by “barriers” to efficiency investments.**

8 A: In an economic sense, barriers refer to features of a marketplace that prevent an
9 optimal economic outcome. The barriers cause the quantity of product transacted and its
10 market-clearing price to be more or less than efficient, resulting in lost economic value.
11 With respect to efficiency investments, some of the more widely-recognized market
12 barriers include:

- 13 ▪ Information barriers in the form of customer awareness of energy efficiency
14 opportunities or scarcity of reliable information on the costs and performance of
15 efficiency technologies.
- 16 ▪ Principal-agent barriers, where the person making the efficiency investment does
17 not benefit from the energy savings (e.g., a landlord installing efficient lighting
18 when the tenant reaps the energy bill savings).
- 19 ▪ Financial barriers, including the (usually) larger up-front cost for efficient
20 equipment and transaction costs related to many small investment decisions rather
21 than fewer large ones.

- 1 ▪ Resource barriers, where decision-makers simply do not have the time or
2 expertise to adequately understand the available options for cost-effective energy
3 savings.

4 **Q: Why is it important to recognize these barriers in the design of energy efficiency**
5 **programs?**

6 A: Because the primary role of efficiency programs is to overcome these barriers.
7 Contrary to some arguments against efficiency programs, utilities or other efficiency
8 program administrators have the ability to influence customer purchasing decisions, just
9 as in any industry. In general, success comes from treating efficiency as a product or
10 service to be sold like any other. The marketers of Coca-Cola must understand and
11 overcome market barriers. Energy efficiency programs are no different. The customer
12 must be aware of them, their benefits must be understood and available to the customer,
13 they must be readily accessible, and they must be priced competitively with the
14 alternatives. It is not sufficient to only address one or two of these factors. As an
15 example, simply providing customers with generic information on efficiency
16 opportunities will generally fail to generate measurable efficiency savings.

17 **Q: Do the Company's proposed programs address these barriers?**

18 A: Yes, to varying degrees, although much of the program detail that would explain
19 their approach has not been provided in the Application or in response to interrogatories.
20 The Company states in response to Staff Interrogatory 3-11 that "the development of
21 implementation processes and operating procedures will be the responsibility of the
22 selected implementation contractor." Much of the detail that would speak to strategies to

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2011-00093
January 17, 2012*

1 overcome barriers, particularly non-financial barriers, is therefore not available for
2 review and comment.

3 **Q: Would the increased incentives that you referred to earlier serve to address any of**
4 **these barriers.**

5 A: Yes, as I stated earlier, higher incentives tend to generate greater customer
6 participation.

7 **Q: Are there specific actions the Company should take to better address other**
8 **barriers?**

9 A: I will make some specific suggestions regarding individual programs later in my
10 testimony. In general, though, participation in an efficiency program should be as easy as
11 possible for the customer. As I note later in my testimony, the best efficiency programs
12 provide customers with “one-stop shopping.” A customer faced with having to choose
13 between a confusing array of different programs is less likely to stick with the effort and
14 become a participant. According to the the Company’s website, there is a single toll-free
15 number that appears to provide a single point-of-contact for both residential and
16 commercial customers interested in efficiency. This is a good first step in this direction.
17 Ideally, this call center helps customers understand the array of opportunities available,
18 provides a common application route, and simplifies the process for the customer.

19 **Q: On which specific programs do you have comments or suggestions?**

20 A: I have comments on all programs except the Residential Lighting Program Phase
21 II.

1 **Q: What are your comments or suggestions on the Commercial Energy Audit**
2 **Program?**

3 A: An on-site audit can be an excellent strategy to engage customers and identify
4 efficiency opportunities. Many efficiency programs use them as an entry-point to the
5 discussion of co-operation between utility and customer in efficiency investments. For
6 example, in New York State, NYSERDA offers an energy audit program specifically for
7 small businesses, who typically find it difficult to invest time and effort in understanding
8 efficiency opportunities.

9 From the program description provided by Witness Newcomb (Schedule 3, pp. 2-
10 3 of 19), the proposed program is limited largely to refrigeration measures in food-service
11 applications. The typical Commercial audit program is more comprehensive and
12 identifies projects across many end-uses that would be eligible for any applicable
13 incentives regardless of program. I am concerned that limiting the audit to such a narrow
14 set of measures is both inefficient and potentially confusing to customers.

15 **Q: How should the Company's Commercial Energy Audit Program avoid this?**

16 A: If the program is to incur the cost and coordination effort required to get an
17 efficiency expert on-site for a facility visit, it would be far more efficient if the auditor
18 reviews and comments on most or all of the energy-consuming systems, not just
19 refrigeration. For example, the Company already offers financial incentives for efficient
20 lighting and HVAC equipment. The audit is an opportunity to direct customers to these
21 incentives. I recommend that the Company broaden the Commercial Audit Program so
22 that a wider range of efficiency opportunities can be identified during the audit and

1 qualify for rebate of the audit cost if implemented by the customer, even if some of those
2 measures are covered by other parts of the commercial program. For example, if the audit
3 identifies an HVAC upgrade that qualifies for an incentive under the HVAC program and
4 the customer proceeds with that installation, the customer should be able to receive the
5 HVAC rebate and at least some portion of the audit cost rebate.

6 **Q: Won't this increase the program's cost and reduce its cost-effectiveness?**

7 A: Potentially, but there may be offsetting cost reductions elsewhere. While program
8 costs might increase, there are likely to be savings elsewhere as the audit provides a
9 pathway to participation that will reduce the HVAC Program's necessary marketing and
10 outreach costs.

11 **Q: Do you have any other comments on the Commercial Audit Program?**

12 Yes, another concern I have is with the incentive provided. The proposed
13 reimbursement of the audit cost (approximately \$1,900) is likely to be too low to
14 encourage investment in any but the most inexpensive measures listed. When incentives
15 cover only a very small portion of measure costs, free-ridership becomes a concern.

16 **Q: Please define what you mean by "free-ridership."**

17 A: As described by Company Witness Newcomb, Schedule 3, a free-rider is a
18 program participant who would have adopted Program-recommended action without
19 Program incentives. When they participate in the program, the program does not realize
20 any savings beyond those that would have naturally-occurred.

21 **Q: How is this related to the incentive level?**

1 A: The lower the financial incentive provided by the program, the greater the
2 likelihood that participants are not motivated to participate by the incentive, all else being
3 equal.

4 **Q: How should the Company address the issue of free-riders?**

5 A: It is the function of program evaluations (EM&V) to assess the level of free-
6 ridership in a given program, such as the Company's previously filed EM&V reports that
7 report on free-ridership estimates. Future reports should continue to do so. To the extent
8 that evaluated free-rider rates become higher than desired or predicted, the Company
9 could then assess the reasons for this and make adjustments to the program. High free-
10 ridership rates suggest that the program is producing very little "net" savings and that
11 program re-design may be needed. The pre-filed testimony of Mr. Hale Powell, also in
12 support of the Environmental Respondents, addresses evaluation issues in greater detail.

13 **Q: What are your comments on the Commercial Duct Testing & Sealing Program and**
14 **the Commercial Refrigeration Program?**

15 A: These programs address important measures that should be part of a
16 comprehensive commercial efficiency portfolio. As I noted earlier, however, the best
17 programs provide an integrated approach to customer interaction. These two proposed
18 programs should be better integrated with an overall approach focused on identifying
19 discretionary equipment upgrades for improved energy performance. The proposed
20 Commercial Audit program will pay a rebate on the audit cost if the customer implements
21 one or more refrigeration measures that are entirely different from the measures covered
22 by the proposed Refrigeration program. Better integration of these offerings will ensure

1 that customers are not forced to select among competing or seemingly redundant
2 offerings.

3 **Q: What are your comments on the Residential Bundle and its component measures?**

4 A: The “programs” in this bundle are each focused on a single measure. As with my
5 comments on the commercial programs, best practice is to avoid program “silos” that
6 make it difficult for customers to implement multiple measures or to receive the guidance
7 they need to make informed choices about efficiency investments. Programs should not
8 be built around a single measure. Therefore, I prefer to think of this “bundle” simply as a
9 Residential Existing Homes program that will offer only four measures. From this
10 perspective, the program is a good start at beginning to develop a comprehensive existing
11 homes program.

12 **Q: Do you have any comments about the individual measures included in this**
13 **program?**

14 A: Yes, I have three major comments. First, the program as proposed limits the
15 eligibility of two of its measures (the heat pump tune-up and heat pump upgrade) to only
16 electric heat customers. There is simply no reason for this; system tune-ups and upgrades
17 are applicable to customers with central air conditioning (CAC) systems as well. A CAC
18 system is virtually identical to a heat pump, the federally required minimum efficiency
19 levels are identical or nearly so, and both typically rely on ducted distribution of
20 conditioned air that would be eligible for the duct sealing component of the bundle. In
21 Virginia’s climate, CAC measures are certainly cost-effective even with the lower
22 savings from cooling-only operation. In Maryland and Pennsylvania, for example, both

1 heat pumps and CAC systems are included in utility HVAC efficiency programs.

2 Therefore, I recommend that the tune-up and upgrade rebates should also be made
3 available for cooling-only systems.

4 **Q: What is your second comment about the measures in the Residential Bundle?**

5 A: There seems to be a disconnect between the nature of the heat pump upgrade
6 measure and the other measures in the program. The audit, duct sealing, and heat pump
7 tune-up are all measures that I would describe as ‘retrofit’ measures, while the baselines
8 and incentives associated with the heat pump upgrade appear to identify this as a lost
9 opportunity measure.

10 **Q: Please define the terms ‘retrofit’ and ‘lost opportunity.’**

11 A: These terms refer to the nature of transactions for energy-consuming equipment.
12 Retrofit refers to a situation where home or business owners have existing equipment that
13 provide needed lighting, heating, cooling, refrigeration, or other services. While this
14 equipment may not use energy efficiently or may have other disadvantages (e.g., age,
15 reliability, product quality), the owner has the option of continuing to use this equipment.
16 Replacing this equipment to reduce energy consumption is a discretionary choice, and the
17 owner must compare the energy-savings benefits of new equipment against the full cost
18 of its installation including labor.

19 Lost opportunity, on the other hand, refers to the case where an owner makes a
20 decision to install new equipment for reasons other than efficiency, due to equipment
21 failure, building or business expansion, performance concerns, or other drivers. Here, the
22 decision is not whether or not to incur the entire cost for a more efficient installation, but

1 whether the incremental cost of a higher-efficiency unit over a standard (or “baseline”)
2 unit is justified given the reduced energy consumption. In this case, the window of
3 opportunity (in terms of time) to influence the energy efficiency of this decision is very
4 narrow, much narrower than in the retrofit market.

5 **Q: Based on these definitions, on what do you base your assumption that the heat-**
6 **pump upgrade is a lost opportunity measure?**

7 A: My assumption that the heat pump upgrade is a lost opportunity measure is based
8 on the reported incentive level and incremental cost of the measure. The incentive being
9 offered is \$205, out of a total incremental cost of \$395. Given that heat pumps cost
10 several thousand dollars to install, these appear to be based on the incremental cost of
11 installing a higher efficiency unit at the time of natural replacement. If a customer claims
12 this rebate for a high-efficiency heat pump to replace a functioning, but inefficient, unit,
13 this is likely to represent a free-rider.

14 **Q: If this is so, why is it a concern with respect to the other measures in the program?**

15 A: First, because of the possibility of high free-rider rates, which could reduce
16 program cost-effectiveness. Second, because, by its very nature, a lost opportunity
17 measure is time-sensitive. The odds that the audit will occur at the time when a
18 replacement heat-pump is needed are very low. Successfully influencing the selection of
19 higher efficiency equipment during the replacement cycle requires a different program
20 approach.

21 **Q: Should the Commission exclude the heat pump upgrade from the Residential**
22 **Program Bundle?**

1 A: No, but I think it is unlikely that the program will generate much participation in
2 this measure and that much of this participation could be comprised of free-riders. The
3 latter would need to be carefully studied as part of evaluation activities.

4 **Q: What is your third comment on the Residential Bundle?**

5 A: Similar to my comment on the commercial audit program, I feel that the
6 residential audit could be improved by addressing a broader range of measures and
7 guidance. In particular, the audit should assess and identify additional retrofit
8 opportunities related to building shell upgrades (e.g., insulation and air sealing) and early
9 retirement of inefficient appliances and equipment (e.g., second refrigerators and
10 freezers, pool pumps). Again, due to the time-sensitive nature of lost opportunity
11 measures, the focus should be on discretionary retrofits.

12 **Part Three: Request to Increase Spending for Two Existing Commercial Programs**

13 **Q: Please describe the Company's request regarding the spending caps for its existing
14 Commercial HVAC Upgrade and Commercial Lighting programs?**

15 A: The Company has requested that the Commission increase the spending caps for these
16 commercial programs by nearly \$11 million, cumulatively. The Company states that this
17 increase is needed to meet 'pent-up' demand for these programs.

18 **Q: Would this increase disproportionately fund commercial sectors programs at the
19 expense of residential or low income programs?**

20 A: No, I do not think so. In the order approving the Company's first set of DSM
21 programs, the Commission authorized spending caps with a far greater emphasis on the
22 residential sector. Therefore, additional funding for these commercial programs will help

1 provide an appropriate balance of funding to the commercial and residential sectors, as
2 befits their relatively equal contribution to Dominion's load. Such balance is both fair and
3 good practice, as the potential efficiency savings from the commercial sector typically
4 exceed those in the residential sector and can be acquired at lower cost.

5 **Q: Is funding balance the only reason to increase the budget for these**
6 **programs?**

7 A: No, not at all. HVAC and lighting measures are typically the source of most
8 program activity in both commercial and residential programs in other jurisdictions.
9 Virtually all efficiency portfolios rely on these measures as the core of their offerings.
10 More importantly in this case, though, is the issue of program consistency. It takes time
11 to build an effective efficiency program infrastructure and even more time to build the
12 customer awareness and relationships that help realize long-lasting and pervasive savings
13 in the marketplace. A program administrator who can be assured of a certain period of
14 stability during which programs can mature will typically perform better than one that is
15 concerned that funding may be quickly removed. Thus, consistency of funding is critical.
16 Were these two programs to have to stop serving customers for a year or more due to
17 funding shortfalls, I would expect greater difficulty with future implementation as the
18 Company tried to re-engage the marketplace and its customers. On-again, off-again
19 programs do not help customer satisfaction or understanding, nor do they encourage
20 investment by the trade allies who often help promote efficiency programs in
21 understanding and tracking current program status.

22 **Q: Should these programs continue as currently designed?**

1 A: For the most part, yes, but I believe that important changes in the lighting
2 marketplace should be addressed in the coming year. The lighting program appears to be
3 offering rebates on technology that is currently or will very shortly be considered
4 baseline due to imminent changes in federal standards. Effective July 2012, Department
5 of Energy standards will ban the manufacture or import of T12 and older, minimally-
6 efficient T8 lamps and ballasts. As a result, standard efficiency T8 lamps will be
7 considered baseline technology. Therefore, I recommend that standard efficiency T8
8 systems and fixtures measures not be offered for rebate for new construction or
9 replacement opportunities. Ideally, the only T8 fixtures and systems rebated would be
10 those that qualify as High Performance T8 (aka "HPT8") or Reduced Wattage T8. The
11 incremental cost of these fixtures over standard T8 fixtures is minimal. The Company
12 implicitly recognizes this; their proposed rebate for an HPT8 4 foot 2 lamp fixture is only
13 \$1 more than the rebate for standard T8 fixture of the same type, just a 20% increase.⁵
14 Given this, the program should make the most of every participant and move their
15 lighting to the higher level of performance offered by HPT8 or Reduced Wattage T8
16 systems. This is far more cost-effective than attempting to return to these customers in
17 several years to move them from regular T8 to HPT8 technology.

18 **Q: How should fixtures qualify as "High Performance?"**

19 A: I recommend that the qualification be based directly on inclusion on the
20 Consortium for Energy Efficiency's lists of qualifying High Performance T8 and
21 Reduced Wattage T8 lamps and ballasts, rather than Dominion's current threshold of

⁵ *Dominion Measures for Commercial Lighting Rebate Program.* <http://dom.com/dominion-virginia-power/customer-service/energy-conservation/pdf/va-lighting-rewards-rebate-chart.pdf>. Accessed 13 January 2012

1 10% more efficient than baseline.⁶ This avoids any confusion over estimates of whether
2 or not a fixture is meets this standard, which can generate confusion over the appropriate
3 baseline, the effect of low power-factor ballasts, changes in lighting levels, etc.

4 **Q: Are there any other measures in the lighting program that should not be included?**

5 **A: Yes, similar to regular T8 lighting, pulse start metal halide (PSMH) fixtures should also**
6 **be considered baseline and not eligible for a rebate, except in discretionary retrofit**
7 **situations. While not based on a federally-mandated standard, this technology has**
8 **become standard practice in most areas.**

9 **Q: What about in the HVAC program? Do you have any comments on the measures**
10 **included in that program?**

11 **A: For the HVAC program, as with most of the other programs, the program is**
12 **targeting only lost opportunity, not retrofit, measures. The incentives offered are not**
13 **sufficient to encourage early retrofit of inefficient yet functional systems. Therefore, I**
14 **suggest the Company also offer a higher incentive level for systems between, say, 5 and**
15 **15 years of age. While this incentive will have to be higher, the savings claimed from this**
16 **measure will also be higher, as they will be based on the old existing equipment**
17 **efficiency rather than the higher current federal minimum. Limiting the rebate to only**
18 **moderately old systems prevents customers whose systems are in fact at the end of their**
19 **useful life from receiving too large a rebate for taking an action they were already going**
20 **to take and eliminates them as a potential free-rider.**

21 **Part Four: Use of the Cost-Effectiveness Tests**

⁶ <http://www.cee1.org/com/com-lt/com-lt-main.php3>

1 **Q: You have presented several recommended modifications to the Company's**
2 **proposed and existing programs. How would these modifications affect the cost-**
3 **effectiveness of the programs?**

4 A: I have not prepared a quantitative estimate of any changes to the cost-
5 effectiveness results as a result of the recommended modifications. I do believe that many
6 of the changes I suggest, however, should either improve the overall cost-effectiveness of
7 the programs or result in no change to some of the cost-effectiveness tests.

8 **Q: Why would some program changes affect only some of the cost-effectiveness tests?**

9 A: Because the tests count different costs and benefits, some program changes will
10 affect one test but not others. The typical example of this concerns incentive costs. In the
11 Total Resource Cost test, the full cost of the measure is counted, regardless of who pays
12 for it. If a utility changes the incentive level for a measure, the TRC result does not
13 change. Because the other tests only count part of the cost of the measure (e.g., both the
14 Ratepayer Impact Measure and the Utility Cost Test only counts the incentive payment,
15 while the Participant Cost test counts the net cost of the measure after incentives), the
16 scores on those tests will change with changes in incentive levels.

17 **Q: So, what effect will increasing customer incentives have on the RIM test and the**
18 **TRC test?**

19 A: Increasing incentives, all else being equal, will decrease the RIM test score while
20 leaving the TRC test score unchanged. This is one reason why many jurisdictions rely
21 primarily on the Total Resource Cost test. It best reflects the net change in economic
22 welfare as a result of an efficiency program. The incentive payment from the utility to the

1 customer is simply a transfer payment that does not result in a change in overall
2 economic welfare. Therefore, the test used to assess changes in economic welfare should
3 be unaffected by the magnitude of this transfer. If the TRC is greater than one, the net
4 economic benefits increase. Contrary to statements made by the Office of Consumer's
5 Counsel in the proceeding on the Company's initial DSM program filing, a RIM score of
6 less than 1.0 does *not* mean that the overall costs of implementing the programs are
7 projected to be higher than the estimated benefits to Dominion's system.⁷

8 **Q: Is it your opinion that programs with RIM scores of less than 1.0 should be**
9 **approved and implemented?**

10 A: Yes. The fact that the Company and the Commission considered and rejected
11 programs that fail the RIM test but score above 1.0 on the Total Resource Cost test
12 (sometimes substantially above 1.0) means that programs that will save Virginia
13 ratepayers money and result in net benefits to the economy are being excluded from the
14 portfolio. Consequently, the Company's customers will pay more for their electricity than
15 is necessary over the long term.

16 **Q: What about the effect on non-participants when the RIM test is less than 1.0?**

17 A: With respect to the RIM test, the Company projects the average residential
18 increase in a monthly bill to be \$1.39 (Petition, p. 20). To save this much on his or her
19 bill, the typical residential customer would need to install 2 CFLs, one low-flow shower
20 head, and one faucet aerator. That is, every customer has the option to be a participant
21 with limited effort and investment. If all customers participate, then their individual

⁷ Direct Testimony of Scott Norwood on behalf of the Attorney General's Division of Consumer Counsel., PUE-2009-00081. Filed 13 January 2010. p. 18.

1 energy savings will outweigh any rate increase, resulting in real energy bill savings for all
2 customers, regardless of the outcome of the RIM test. I note that the RIM test is also
3 called the “non-participant” test. The smaller the number of non-participants, the less
4 relevant the RIM test becomes.

5 **Q: Should the Commission then ignore the outcome of the RIM test?**

6 A: No single test should be ignored, but I do not believe that the RIM test should be
7 accorded the primary importance that it has. Distributional equity is important, but by
8 emphasizing the RIM test, the Commission makes the assumption that the current
9 distribution of cost burden is exactly right and that any change to that distribution is
10 inappropriate. Given the relatively small change in rates and the very real economic
11 benefits approaching \$1 billion from just five years of program implementation, even
12 greater investment in efficiency represents a positive outcome for Virginia ratepayers.

13 **Q: Are you aware of any legislation pending in Virginia to address this problem that
14 you have identified?**

15 A: Yes, I understand from media reports that Governor McDonnell’s energy package
16 includes a bill that would reform the test for cost-effectiveness of energy efficiency
17 programs. The bill, HB 312, states that any efficiency program is in the public interest if
18 “the net present value of the benefits exceeds the net present value of the costs as
19 determined by not less than any three of the following benefit cost tests: (i) the Total
20 Resource Cost Test; (ii) the Utility Cost Test (also referred to as the Program
21 Administrator Test); (iii) the Participant Test; and (iv) the Ratepayer Impact Measure
22 Test.”

1 **Q: How does the Governor's proposed legislation address your concern?**

2 A: The RIM test is most often the test where the measured costs exceed the measured
3 benefits. Referring to Company Witness Newcomb Schedules 11 and 13, all of the
4 proposed programs and the overall portfolio, for all sensitivity runs, have BCR's
5 exceeding 1.0 in all of the tests except the RIM test. Therefore, the proposed legislation
6 would likely serve to increase the number, types, and magnitude of efficiency programs
7 that would be considered in the public interest based on cost-effectiveness criteria, even if
8 these programs included greater levels of incentives or other spending to spur greater
9 participation and higher levels of savings. I believe this would dramatically increase
10 progress towards achieving the Commonwealth's 10% savings goal.

11 **Q: Does this conclude your testimony?**

12 A: Yes.



JEFFREY M. LOITER
MANAGING CONSULTANT

Mr. Loiter has over 14 years of consulting experience in energy and natural resource issues. His energy experience includes policy, planning and program design, research on renewable and efficiency technologies, electricity transmission systems, integrated resource planning and savings verification. As a Managing Consultant, Mr. Loiter manages projects, oversees staff development, and contributes to firm management in the areas of hiring and business development.

PROFESSIONAL EXPERIENCE

Optimal Energy, Inc.

Bristol, VT

Managing Consultant, 2006-present

- Managing Optimal's participation in a team developing a Five-Year Energy Efficiency and Demand Response Plan for the Tennessee Valley Authority. Optimal's role focused on programs for the commercial sector in TVA's service territory, encompassing efforts to reach a variety of markets and end-uses, including specific offerings for both very large and small commercial entities.
- Supporting Efficiency Vermont Business Energy Services group with technical analysis, market research, and program design consultation. Recent projects include market characterization studies of refrigeration, lodging establishments, and food service entities; and developing several Technical Resource Manual entries.
- Supporting Massachusetts Energy Efficiency Advisory Council on program planning and implementation and technical analysis. Currently participating in the CHP Working Group, guiding program implementation strategies and analytical approaches.
- Supporting program implementation and on-going program design and development for Orange and Rockland Utilities. Previously managed the preparation of a DSM plan and Commission filings for this client. The project included on-site customer audits and residential surveys, efficiency program designs, and an efficiency potential study.
- Prepared comments and related materials on utility IRP filings in support of the Missouri Department of Natural Resources. Review focused on compliance with IRP regulations and critique of filed DSM plans as compared to best-practice.
- Led Optimal's participation in preparing a Technical Resource Manual for the Mid-Atlantic States (Maryland, Delaware, District of

Columbia), for the Northeast Energy Efficiency Partnerships' Regional EM&V Forum.

- Supported the Maryland Energy Administration in their review of utility energy efficiency plans and the design and implementation of state-delivered efficiency programs.
- Provided recommendations to improve a targeted DSM program being delivered under contract to a major northeast electric utility. Interviewed program staff and provided recommendations based on best practice approaches for similar target markets.
- Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.
- Conducted potential analysis for a Canadian Atlantic province, including commercial and institutional sector program design and overall analytical oversight.
- Developed residential potential analysis for the non-transmission alternative to a proposed transmission line upgrade in Vermont.
- Prepared report on efficiency potential in Texas in support of discussions related to proposed expansion of coal-fired generating capacity, for two major NGOs.

Independent Consultant

Cambridge, MA

2005-2006

- For the Massachusetts Renewable Energy Trust SEED Initiative, evaluated renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards recommended for approval totaled \$1.4 million.
- Led an effort to draft a whitepaper on policies to encourage investment in electricity transmission facilities.
- Prepared two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in Petroleum Technology Quarterly (1Q 2006) and BCC Research/Energy Magazine (2006).

Industrial Economics, Incorporated

Cambridge, MA

Associate, 1997-2000; Senior Associate, 2001-2004

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Incorporated

New Orleans & Boston

1991-1995

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

EDUCATION

M.S., Technology & Policy, Massachusetts Institute of Technology, Cambridge, MA, 1997

B.S. with distinction, Civil and Environmental Engineering, Cornell University, Ithaca, NY, 1991

PUBLICATIONS

"From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers," (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings*, Pacific Grove, CA, August 2008.

National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies*. Prepared by Philip Mosenthal and Jeff Loiter, Optimal Energy, Inc. December.

Loiter J.M and V. Norberg-Bohm (1999), "Technology policy and renewable energy: public roles in the development of new technologies," *Energy Policy* Vol.27 no.85-97

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing by deposit in the U.S. Mail, first class, postage prepaid:

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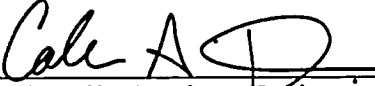
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DATED: January 17, 2012



Cale Jaffe, Southern Environmental Law Center

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January 15, 2013

VIA ELECTRONIC FILING

The Honorable Joel H. Peck
Office of the Clerk, State Corporation Commission
c/o Document Control Center
P.O. Box 2118
Richmond, VA 23218-2118

RE: Petition of Virginia Electric and Power Company for approval to extend two demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia

Case No. PUE-2012-00100

Dear Mr. Peck:

Enclosed for filing in the above-captioned matter is the pre-filed direct testimony of Jeffrey Loiter, of which there is a public version only, on behalf of Appalachian Voices, Chesapeake Climate Action Network, and the Virginia Chapter of the Sierra Club (collectively "Environmental Respondents").

Should you have any questions regarding this filing, please contact me at (434) 977-4090. Thank you for your assistance.

Sincerely,



Caleb A. Jaffe, Southern Environmental Law Center

cc: Commission Staff and Service List

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing by deposit in the U.S. Mail, first class, postage prepaid:

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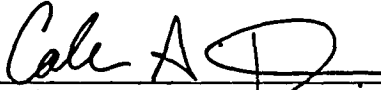
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DATED: January 15, 2013



Cale Jaffe, Southern Environmental Law Center

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2012-00100
January 15, 2013*

**TESTIMONY
OF
JEFFREY LOITER**

**ON BEHALF OF
APPALACHIAN VOICES, THE CHESAPEAKE CLIMATE ACTION NETWORK, AND
THE VIRGINIA CHAPTER OF THE SIERRA CLUB
("ENVIRONMENTAL RESPONDENTS")**

**Virginia State Corporation Commission
Case No. PUE-2012-00100**

JANUARY 15, 2013

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2012-00100
January 15, 2013*

1 **Q. Please state your name and business address.**

2 A. My name is Jeffrey Loiter and my business address is Optimal Energy,
3 Incorporated, 14 School Street, Bristol, VT 05443.

4 **Q. On whose behalf are you testifying?**

5 A. I am testifying on behalf of Appalachian Voices, the Chesapeake Climate Action
6 Network, and the Virginia Chapter of the Sierra Club (collectively, "Environmental
7 Respondents").

8 **Q. Mr. Loiter, by whom are you employed and in what capacity?**

9 A. I employed as a Managing Consultant by Optimal Energy, Inc., a consultancy
10 specializing in energy efficiency and utility planning. My clients include utilities, non-
11 governmental organizations, state energy offices and efficiency councils, and third-party
12 program administrators. For example, I provide Orange & Rockland Utilities, an electric
13 and gas utility based in New York, with consulting services related to energy efficiency
14 program design and implementation. I also provide program planning, implementation
15 guidance and technical analysis to the Massachusetts Energy Efficiency Advisory
16 Council, which helps design and approve utility- and municipal aggregator-operated
17 energy efficiency programs in the state of Massachusetts.

18 **Q. Please summarize your work experience and educational background.**

19 A. I have 16 years of experience in environmental and economic consulting. For the
20 past six years, I have been engaged in a variety of work at Optimal Energy related to
21 energy efficiency program design and analysis. For example, I prepared two documents
22 for inclusion with EPA's *National Action Plan for Energy Efficiency*, a guidebook on

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2012-00100
January 15, 2013*

1 conducting efficiency potential studies and a handbook describing the funding and
2 administration of clean energy funds.¹

3 In my capacity as a Managing Consultant at Optimal, I also advise clients on a
4 variety of issues related to efficiency program design and implementation. For example, I
5 recently contributed to a Five-year Energy Efficiency and Demand Response Plan for the
6 Tennessee Valley Authority. I have also participated in several studies of efficiency
7 potential and economics, including ones in New York, Vermont, Texas, Massachusetts,
8 and Prince Edward Island. These studies have ranged from macro-level assessments to
9 extremely detailed, bottom-up assessments in which I evaluated thousands of energy
10 efficiency measures among numerous market segments.

11 Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial
12 Economics, Inc. in Cambridge, Massachusetts. I have a *B.S. with distinction* in Civil and
13 Environmental Engineering from Cornell University and an *M.S.* in Technology and
14 Policy from the Massachusetts Institute of Technology. My resume is provided as Exhibit
15 ER-JML-1.

16 **Q. Have you previously testified before the Virginia State Corporation Commission**
17 **(“the Commission” or “SCC”)?**

18 A. Yes, I testified on behalf of the Environmental Respondents in the following SCC
19 cases: PUE-2009-00023, PUE-2011-00092, and PUE-2011-00093.

20 **Q: What is the purpose of your testimony?**

¹ These documents can be found at http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf and http://epa.gov/cleanenergy/documents/clean_energy_fund_manual.pdf, respectively.

1 A: The purpose of my testimony is to present the conclusions of my review of
2 Dominion's petition in this docket. I focus only on (i) Dominion's request for approval to
3 extend the AC Cycling and Low Income Programs; (ii) Dominion's request for approval
4 of an administrative approval process; and (iii) Dominion's progress towards meeting its
5 share of the statewide 10 percent savings goal, particularly as it relates to future lost
6 revenue calculations.

7 **Q. Are you submitting exhibits along with your testimony?**

8 A. Yes. My testimony includes Exhibit ER-JML-1 – Resume of Jeffrey Loiter.

9 **Part One: Summary of Conclusions and Recommendations**

10 **Q: Please summarize your conclusions and recommendations based on your review of**
11 **Dominion's application and testimony.**

12 A: With respect to the Low Income and AC Cycling Programs, I support their
13 extension, although with some caveats related to cost-effectiveness and contribution
14 towards energy reduction goals. I also support the proposed administrative approval
15 process, although I believe it could be modified to afford Dominion greater flexibility
16 that would make the programs more effective by allowing the Company to react quickly
17 to customer feedback and changing market conditions. Last, I note that the Company
18 appears to be falling further behind the pace necessary to achieve its share of the
19 Commonwealth's 10 percent energy reduction goal. Part of the shortfall, I believe, is due
20 to concerns about future lost revenue collections. I offer some thoughts on how to address
21 those concerns.

1 **Part Two: The Company's Request to Extend Two Phase I DSM Programs**

2 **Q: Please describe the Company's extension request?**

3 **A:** The Company requests Commission approval to extend two Phase I DSM
4 programs, the AC Cycling Program and the Low Income Program. The former is a peak
5 shaving program while the latter is an energy efficiency program, as those terms are
6 defined in the Virginia Code. Both programs target residential customers.

7 **Q: Has the Company made any changes to these programs since their approval?**

8 **A:** Yes, there have been several changes to the Low Income Program both in terms
9 of the customers targeted and measures offered. The Program, which was modeled
10 initially to target homeowners, has been made available to certain qualifying customers
11 who rent, rather than own, their homes. Attic insulation has been added as a program
12 measure and the amount of CFLs available to participating customers has been increased
13 from four to six.

14 **Q: Do you have any comments about these changes to the Low Income Program?**

15 **A:** Yes. These program enhancements are an improvement to the Program that
16 should result in additional cost-effective energy savings and greater bill savings for the
17 customer than the program as initially modeled. I should also note that some of the
18 program additions, such as the availability to renters and increase in CFL limit, are
19 similar to those recommended by Environmental Respondents' Witness William
20 Steinhurst during the hearing in case no. PUE-2009-00081.

21 **Q: Do you think that the proposed extension of the Low Income Program should be**
22 **approved?**

*Direct Testimony of Jeffrey Loiter
on behalf of Environmental Respondents
Virginia SCC Case No. PUE-2012-00100
January 15, 2013*

1 A: Yes, the extension should be approved. The Low Income Program serves an
2 important role in ensuring that the benefits of energy efficiency, including bill savings,
3 are made available to low income customers. That said, I do have some concerns about
4 the Program and believe that it should be improved.

5 **Q: Please explain your concerns.**

6 A: I am concerned about the cost-effectiveness of this program and the results of the
7 most recent evaluation, measurement and verification (“EM&V”) report. I therefore
8 believe that the Company should make changes to the Program in the near future, and my
9 recommendation to approve the Program is limited to the two years requested in the
10 petition.

11 **Q: Please describe your concern about the cost-effectiveness of the Low Income**
12 **Program?**

13 A: I reviewed the information presented in Company Witness Newcomb’s Schedule
14 4 (“RCN Schedule 4”) and the information presented in the Company’s confidential
15 response to SCC Staff’s discovery request, Staff Set 01-2a (RCN). Based on my review,
16 and without disclosing any confidential information, I believe the total resource cost
17 (“TRC”) benefit/cost ratio should be significantly lower than is reported by the Company
18 in RCN Schedule 4. Specifically, I believe the TRC ratio should be the same as the utility
19 cost test ratio, which is also presented in RCN Schedule 4. This would change the score
20 from 5.34 to 0.32, on an individual program basis.

21 **Q: What is your basis for this conclusion?**

1 A: The Company's TRC calculation for the Low Income Program is inconsistent
2 with my understanding of how this calculation is typically performed. Specifically, I am
3 concerned about the relative amount of net present value ("NPV") costs the Company
4 includes in its TRC calculation. RCN Schedule 4 reports that the total NPV costs of the
5 Low Income Program are approximately \$22.9 million from the utility cost test
6 perspective, but less than \$1.4 million from the TRC perspective. As shown on pages 4
7 and 6 of Schedule 46B, the total cost of the Program, if extended, exceeds \$5 million in
8 2013 alone, nearly \$4.8 million of which are one-time incentive costs. The one-time
9 incentive costs, which constitute the bulk of the total program costs, do not appear to be
10 included in the Company's costs estimate from the TRC perspective, which is less than
11 \$1.4 million.

12 **Q: Why do you think the Company did not include the incentive costs in its TRC cost**
13 **calculation?**

14 A: I believe the Company did not include the incentive costs due to its interpretation
15 of the "customer costs" component of the TRC cost equation. On page 16 of his
16 testimony, Witness Newcomb provides the TRC formula, which includes utility
17 administrative costs plus "customer costs" on the cost side of the benefit-cost ratio. If one
18 begins with the assumption that customers pay the entire cost of efficiency investments
19 out of their own pocket and then receive a rebate of some portion of this spending from
20 the utility, then "customer costs" could be interpreted to mean the cost of the efficiency
21 investment, or "measure costs." The incentive payment from the utility to the customer
22 would, appropriately, not enter into the equation. I suspect that the Company has instead

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on behalf of Environmental Respondents
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1 used *net* customer cost in their calculation, which is the measure cost less incentive
2 payments. Because the Low Income Program covers 100% of the cost of the efficiency
3 measures, the net customer cost is zero, as demonstrated by the lack of any NPV costs for
4 the Participant test, as reported in RCN Schedule 4. Done this way, the costs of
5 implementing the efficiency measures in the low income program do not appear
6 anywhere in the TRC calculation. I believe this calculation is flawed.

7 **Q: Are you suggesting that the TRC test should count incentive payments as a cost?**

8 **A:** No. As Witness Newcomb notes on page 16 of his testimony, the TRC test views
9 customer incentives as a transfer payment from the utility to the participant. However, in
10 the Low Income Program, Dominion is not providing an incentive in the form of a cash
11 payment to the customer. Rather, it is a direct install program in which Dominion pays
12 contractors and suppliers for the efficient equipment and materials (e.g., insulation,
13 CFLs) and the labor to install this equipment. This spending should be considered
14 somewhere in the cost formulation so it does not disappear from TRC cost accounting. In
15 other words, the TRC test should include the *actual* costs of the efficiency investment,
16 which is composed of the administrative costs incurred by the utility plus the cost of
17 installing the efficiency measures. This latter category of costs includes labor and
18 equipment, and is a cost under the TRC test regardless of whether the utility or customer
19 pays for it.

20 **Q: What would be the impact on the cost-effectiveness of the Low Income program if**
21 **the TRC calculation were modified as you describe?**

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on behalf of Environmental Respondents
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1 A: The Low Income program would have a TRC benefit/cost ratio of 0.32, equal to
2 the utility test benefit/cost ratio.

3 **Q: Do you still support the approval of a program with such a low TRC result?**

4 A: I do.

5 **Q: Please explain why.**

6 A: I support the Low Income Program for a few reasons. First, there are public policy
7 reasons to implement energy efficiency programs targeted at low-income customers. The
8 Low Income Program provides services to those customers who are likely to suffer the
9 most hardship from high electric bills, whether by virtue of their limited income or the
10 fact that low income residences are typically less efficient than the average residence.

11 By reducing the total amount of electricity required for the same end uses, energy
12 efficiency programs lower electricity bills and save customers money. However,
13 investing in energy efficiency typically requires an up-front investment in order to reap
14 future bill savings. This “first-cost” barrier is highest for low-income customers, who
15 may not have the necessary capital, whether from savings or the ability to borrow at
16 reasonable interest rates. Low income energy efficiency programs, therefore, play a
17 critical role in helping low income customers install measures that will lower their energy
18 bills. Although I am not a lawyer and am not offering a legal opinion, I understand that
19 §56-576 now provides that “[a]n energy efficiency program may be deemed to be ‘in the
20 public interest’ if the program provides measurable and verifiable energy savings to low-
21 income or elderly customers.” Virginia General Assembly, 2012 Session, Acts of
22 Assembly, Chapter 210 (effective March 10, 2012). It is important that a comprehensive

1 efficiency portfolio offer all customers, including low-income customers, a means to
2 reduce their energy consumption in ways that are financially feasible.

3 Second, the low TRC result is driven in part by a very low realization rate
4 reported for this program in the April 2012 EM&V report.² This evaluation was based on
5 a billing analysis that attempted to discern reductions in participating customer
6 consumption by performing a statistical regression on pre- and post-installation
7 consumption data. Based on this analysis, the evaluator chose to assume zero energy
8 savings for those customers who did not install either attic insulation or low-flow shower
9 heads. That is, zero savings was assumed for a home that received an audit, six CFLs,
10 water heater tank wraps, and envelope sealing, despite the fact that these measures were
11 directly installed by the audit team. Because these measures represent a small fraction of
12 total household energy usage, I am concerned that any billing analysis would be unable to
13 discern savings from these measures therefore underestimate savings attributable to the
14 Low Income Program.

15 **Q: Are there any additional factors that should be considered?**

16 **A:** Yes. An important part of successful program implementation is consistency. By
17 extending the existing Low Income Program, the Company can assure consistency for
18 customers, market partners, and implementation staff as it looks for ways to further
19 improve the program over the next two years. As I have discussed in prior testimony, it
20 takes time to build an effective efficiency program infrastructure and even more time to
21 build the customer awareness and relationships that help realize long-lasting and

² April 2012 Evaluation, Measurement and Verification Report for Dominion Virginia Power, Case PUE-2010-00084. Prepared by KEMA, Inc.

1 pervasive savings in the marketplace. Thus, consistency of funding is critical. If programs
2 have to stop serving customers for a year or more, we should expect greater difficulty
3 with future implementation as the Company tried to re-engage the marketplace and its
4 customers. On-again, off-again programs do not help customer satisfaction or
5 understanding, nor do they encourage investment by the trade allies who often help
6 promote efficiency programs in understanding and tracking current program status.

7 **Q: You mentioned that the Low Income Program should be improved. Please explain**
8 **your recommendation.**

9 **A:** While I support approval of the Low Income Program, the Company should still
10 strive to improve the program's cost-effectiveness in the next year or two. Low Income
11 programs that score much higher on the utility and TRC tests do exist; I suggest that
12 Dominion pursue efforts to improve the program design and to more carefully evaluate
13 the results of the program.

14 On the program design side, the Company should revisit the overall costs of
15 reaching and treating each customer with the objective of reducing cost per customer and
16 increasing the savings that can be realized from each visit. On the evaluation side, the
17 Company should seek refinements in the billing analysis, such as increased sample size
18 or more detailed regression modeling to improve the realization rate, but only to the
19 extent supported by the data. Other evaluation methods should also be considered; billing
20 analysis is used only for the Low Income Program among all of the Company's
21 programs. These topics may be appropriate for discussion in the stakeholder review
22 process ("SRP").

1 **Q: What is your view of the AC Cycling Program?**

2 A: The AC Cycling Program is a peak shaving program, as the term is defined in
3 Virginia law. Again, although I am not a lawyer, I am aware that § 56-576 of the Code
4 defines peak-shaving as “measures aimed solely at shifting time of use of electricity from
5 peak-use periods to times of lower demand by inducing retail customers to curtail
6 electricity usage during periods of congestion and higher prices in the electrical grid.”
7 Peak shaving programs like the AC Cycling program can provide important benefits,
8 including increasing grid reliability and stability and deferring the need for investments in
9 new capacity or transmission and distribution infrastructure.

10 **Q: Do you have any concerns about the Company’s request to extend the Program?**

11 A. I do. The AC Cycling Program is not an energy efficiency program, and the
12 Company does not attribute energy savings to it nor does the April 2012 EM&V filing
13 report energy savings. However, in its petition (pages 7, 9-10), the Company discusses its
14 extension request in the context of furthering Virginia’s goal of “reducing the
15 consumption of electric energy by retail customers through the implementation of such
16 programs by the year 2022 by an amount equal to ten percent of the amount of electric
17 energy consumed by retail customers in 2006” (“10 percent goal”).³ Although reducing
18 peak capacity serves an important function, the AC Cycling Program does not have
19 energy savings attributed to it and therefore does not help the Company reach the 10
20 percent goal. To date, the Company remains far from reaching this goal, which I discuss
21 further in Part Four of my testimony.

³ Virginia Acts of Assembly, Reconvened Session, identical Chapters 752 and 855 (approved March 30, 2009 and April 8, 2009, respectively; effective July 1, 2009).

1 **Q. Does this lack of energy savings mean that the Commission should reject the**
2 **Company's request to extend the AC Cycling Program?**

3 A. No, I don't believe so. However, the Company should address the potential
4 benefits of the program in their proper context – reducing peak demand, not contributing
5 towards the reduction of energy consumption. Also, if the Company or the Commission
6 believes that there are limited resources available for implementing DSM programs, the
7 priority should be on those programs that deliver energy savings towards the
8 Commonwealth's goal. Such programs would also provide some measure of peak
9 demand reduction.

10 **Part Three: The Company's Proposed Administrative Approval Process**

11 **Q: Can you please describe the Company's request for an Administrative Approval**
12 **Process?**

13 A: The Company is requesting a process by which Staff would review requests to
14 modify, remove, or add measures to previously-approved DSM programs, when those
15 requests would not increase the projected direct program costs and would not change the
16 projected energy or capacity savings.

17 **Q: Do you support this proposal?**

18 A: Yes, very much so. I previously testified before the Commission on the
19 importance of flexibility in program implementation to respond to changes in markets
20 and technologies without having to return to the Commission for approval. At that time, I
21 recommended that the Commission consider allowing the Company flexibility within
22 programs, such as revising incentive levels to respond to market conditions and customer

1 response. In this case, the proposed Administrative Approval process specifically
2 excludes changes to participant incentives.

3 While I support the process as filed, I believe it should include greater flexibility
4 than proposed by the Company. It will be a good start for the Company to be able to
5 adjust the measures available to customers, but having the flexibility to adjust the
6 measure mix by responding to customer demand with revised incentives would, I believe,
7 result in greater efficiencies in program delivery and potentially reduce savings
8 acquisition costs. For example, if the Company finds that a particular measure is highly
9 popular with customers and may drive an over-expenditure of program budget, under the
10 proposed process the Company would only have the recourse of eliminating this measure
11 and its attendant savings. It would be far better for the Company to reduce the measure
12 incentive to preserve program budgets but retain the savings from this activity.

13 **Q: Do you have any additional recommendations concerning the proposed process?**

14 A. Yes. I recommend that the Company also notify participants in the SRP (in
15 addition to parties to the DSM proceeding in which the program was approved) when it
16 files a request with the SCC Staff under the administrative process.

17 **Part Four: Dominion's progress towards achieving its share of the 10 percent goal**

18 **Q: You mentioned earlier in your testimony that the Company remains far from
19 achieving the 10 percent energy savings goal. Can you elaborate?**

20 A: Yes. The total projected energy savings from the Company's eight approved
21 efficiency programs reach just 1.1 percent of 2006 sales, far short of the 10 percent goal.
22 On pages 9-10 of his direct testimony, Witness Newcomb confirms that the Company

1 projects it will reach roughly one-tenth of the target (applied to Dominion's 2006
2 jurisdictional retail sales) with the approved programs and extension of the Low Income
3 and AC Cycling Programs, should they be approved. Even adding the savings from other
4 potential programs that the Company labels "future programs" in its 2012 IRP, energy
5 savings reaches only 4.5 percent of 2006 sales by the target year of 2022, less than half of
6 the goal.⁴

7 Furthermore, 60 percent of the projected savings in 2022 result from a single
8 activity, the Voltage Conservation Program. While this program may be a cost-effective
9 means of reducing total load, this has not yet been determined and I do not believe it
10 should represent such a large portion of the 10 percent savings portfolio.

11 **Q: How does this compare with other utilities?**

12 A: Not favorably. As I explained back in the energy efficiency potential docket in
13 2009, there are several electric power providers throughout the country that have
14 achieved annual savings of 0.9% or greater. *See* Testimony of Jeffrey Loiter on behalf of
15 Southern Environmental Law Center, at pages 11-12, PUE-2009-00023 (pre-filed July
16 31, 2009).

17 **Q: What are the overall economic outcomes from the Company's efficiency programs?**

18 A: According to the latest evaluation results, Dominion's efficiency programs in
19 Virginia have saved over 176,000 MWh through the end of 2011.⁵ This represents over
20 \$15 million in customer bill savings each year, assuming a marginal residential retail rate

⁴ In its 2012 IRP, Dominion reports total Virginia sales in 2006 of 73,705 GWh (Appendix 2B) and projects savings in 2022 of approximately 592 GWh from approved programs (Appendix 3P) and 2,752 GWh from future programs (Appendix 5I). Together with the 5.5 GWh from the extended programs proposed in this proceeding, the Company is projecting approximately 3,349 GWh of savings, or 4.5 percent of 2006 sales.

⁵ April 2012 EM&V report at 1-2.

1 of 8.6 cents/kWh. Given that these savings represent only a small fraction of the potential
2 savings that would result from achieving the 10 percent goal, the potential bill savings for
3 the Company's customers are much greater, in the hundreds of millions of dollars
4 annually.

5 **Q: But aren't those bill savings realized by energy efficiency program participants at a**
6 **cost to non-participants?**

7 A: It is true that non-participant costs, as measured by the RIM test, often result in
8 programs that can appear not to be cost-effective. But the RIM test takes a limited
9 perspective on the costs and benefits of efficiency that, I believe, masks the true value of
10 the programs. By focusing solely on the costs to non-participants, it addresses
11 distributional effects, but ignores overall economic outcomes.

12 **Q: How would you characterize these distributional effects as compared to overall**
13 **economic outcomes?**

14 Energy efficiency and DSM resources more generally benefit all customers
15 because they are a cheaper and less risky resource than traditional supply side generation.
16 While efficiency may result in a shift in costs from non-participants to participants,
17 supply-side investments also result in cost shifts. For example, an existing customer with
18 flat or decreasing consumption will still be subject to rate increases resulting from
19 supply-side investments despite the fact that they have not contributed to the load growth
20 that might necessitate such investments. I note that the current riders for the Warren
21 County Power Station, the Bear Garden Generating Station, and the Virginia Hybrid
22 Energy Center total 0.68 cents per kWh for residential customers, as compared with

1 0.024 cents per kWh for the C2A efficiency rider. Regardless, it remains true that energy
2 efficiency can help a utility get the most out of its existing generation and transmission
3 assets or facilitate the retirement of aging generation before seeking rate increases to pay
4 for billion-dollar supply-side investments or retrofits.

5 **Q: As energy savings rise closer to the 10 percent goal, won't net lost revenue costs**
6 **increase dramatically?**

7 A: I understand that there are concerns that future lost revenue awards are uncertain
8 and could become larger than the implementation costs of the efficiency programs. I
9 think this is an important concern for the Commission to address. One way to address it
10 would be through improved EM&V and clear rules that place a strict burden on the
11 Company prior to granting any "net lost revenue" requests. It may be that a new
12 rulemaking docket on net loss revenues is needed to address some of the questions that
13 have been raised in past DSM proceedings.

14 **Q: What would be the goal of a "net loss revenue" rulemaking docket?**

15 A: Clear rules for the collection of net loss revenues would reiterate that lost
16 revenues should not represent an additional cost burden to ratepayers as compared to the
17 situation where efficiency investments are not made. In other words, the burden should
18 be on the Company to demonstrate that the revenue collected from ratepayers as a result
19 of lost revenue adjustments will not exceed that which the Company would have
20 otherwise collected in the absence of efficiency programs. These amounts are simply
21 "revenues" in either case, and one should not ultimately be greater than the other. Since

1 last testifying on this issue, a report prepared by Synapse Energy Economics for the
2 National Home Performance Council provides a succinct description of this concept:

3 The RIM test is heavily influenced by the lost revenues to the utility.
4 However, lost revenues are not a true cost to society. Lost revenues
5 represent a "transfer payment" between efficiency program participants
6 and non-participants...In this way, lost revenues are not a new or an
7 incremental cost in the same way that the program administration costs are
8 a new and incremental cost of implementing energy efficiency
9 programs...⁶

10
11 Rules on lost revenues need to ensure that net lost revenues are appropriately
12 calculated so they do not become a windfall for the utility.

13 **Q: Now, in this docket, the Company has not proposed to recover lost revenue from the**
14 **proposed programs, have they?**

15 **A: No, not at this time.**

16 **Q: Does this mean there is great uncertainty in the amount of lost revenue that will**
17 **need to be recovered from ratepayers in the future**

18 **A: No. A robust EM&V process should be used to ensure confidence in program**
19 **outcomes and energy savings in support of lost revenue claims. In advance of these**
20 **evaluation results, I think it is appropriate to defer recovery of these lost revenues, but**
21 **evaluation should be given high importance in terms of funding. Based on my comments**
22 **about the importance of revisiting the evaluation of the Low Income Program, I believe**
23 **evaluation spending for both of the proposed program extensions should be increased.**

24 **Q: Does this conclude your testimony?**

25 **A: Yes.**

⁶ Woolf, T. et al. *Best Practices in Energy Efficiency Program Screening*. Prepared for the National Home Performance Council. 23 July 2012.

Exhibit ER-JML-1



**JEFFREY M. LOITER
MANAGING CONSULTANT**

Mr. Loiter has over 14 years of consulting experience in energy and natural resource issues. His energy experience includes policy, planning and program design, research on renewable and efficiency technologies, electricity transmission systems, integrated resource planning and savings verification. As a Managing Consultant, Mr. Loiter manages projects, oversees staff development, and contributes to firm management in the areas of hiring and business development.

PROFESSIONAL EXPERIENCE

Optimal Energy, Inc.

Bristol, VT

Managing Consultant, 2006-present

- Leads Optimal's energy efficiency consulting services to the Connecticut Municipal Electric Energy Cooperative (CMEEC). These services include program planning, program savings analysis and reporting, developing incentive and delivery strategies, and managing CMEEC's participation in the ISO-NE Forward Capacity Market. The latter has included drafting M&V plans specifying procedures for meeting all ISO-specified M&V rules, including data management calculation of demand reduction values for monthly submission. Mr. Loiter also manages CMEEC's participation in new FCM auctions and arranges for annual certification reviews.
- Submitted expert testimony on behalf of environmental interveners or state agencies in cases related to utility Integrated Resource Plan and Demand Side Management Plan filings. Cases typically involve filing review, developing alternative analyses, drafting pre-filed testimony, and appearing before public service commissions for cross-examination. Cases have included utility filings in Virginia, Ohio, Arkansas, Pennsylvania, Maryland, and Missouri.
- Supporting program implementation and on-going program design and development for Orange and Rockland Utilities. Previously managed the preparation of a DSM plan and Commission filings for this client. The project included on-site customer audits and residential surveys, efficiency program designs, and an efficiency potential study.
- Led Optimal's participation in preparing a Technical Resource Manual for the Mid-Atlantic States (Maryland, Delaware, District of Columbia), for the Northeast Energy Efficiency Partnerships' Regional EM&V Forum.

- Managed Optimal's participation in a team developing a Five-Year Energy Efficiency and Demand Response Plan for the Tennessee Valley Authority. Optimal's role focused on programs for the commercial sector in TVA's service territory, encompassing efforts to reach a variety of markets and end-uses, including specific offerings for both very large and small commercial entities.
- Supporting Efficiency Vermont with technical analysis, market research, and program design consultation. Recent projects include market characterization studies of refrigeration, lodging establishments, and food service entities; and developing several Technical Resource Manual entries.
- Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.
- Led or contributed to several studies of efficiency potential, ranging from meta-analyses to detailed sector-specific assessments. Assessments have included both the residential sector and the commercial/industrial sectors, in locations including New York, Vermont, New England, Texas, and a Canadian Atlantic province.

Independent Consultant

Cambridge, MA

2005-2006

- For the Massachusetts Renewable Energy Trust SEED Initiative, evaluated renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards recommended for approval totaled \$1.4 million.
- Led an effort to draft a whitepaper on policies to encourage investment in electricity transmission facilities.
- Prepared two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in Petroleum Technology Quarterly (1Q 2006) and BCC Research/Energy Magazine (2006).

Industrial Economics, Incorporated

Cambridge, MA

Associate, 1997-2000; Senior Associate, 2001-2004

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Incorporated
1991-1995

New Orleans & Boston

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

EDUCATION

M.S., Technology & Policy, Massachusetts Institute of Technology, Cambridge, MA, 1997

B.S. with distinction, Civil and Environmental Engineering, Cornell University, Ithaca, NY, 1991

PUBLICATIONS & PRESENTATIONS

"Collaboration that Counts: The Role of State Energy Efficiency Stakeholder Councils," (with D. Sosland, M. Guerard, and J. Schlegel), *2012 ACEEE Summer Study on Energy Efficiency in Buildings*, Pacific Grove, CA, August 2012.

"Persistence and Cost of Behavioral Programs," presented at National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, SC, June 2012.

"Impending EISA Lighting Standards: Impacts on Consumers and Energy Efficiency Lighting Programs," presented at National Association of Regulatory Utility Commissioners Annual Meeting (with M. DiMascio), Atlanta, GA, November 2010.

"From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers," (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings*, Pacific Grove, CA, August 2008.

National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies*. Prepared by Philip Mosenthal and Jeff Loiter, Optimal Energy, Inc. December.

Loiter J.M and V. Norberg-Bohm (1999), "Technology policy and renewable energy: public roles in the development of new technologies," *Energy Policy* Vol.27 no.85-97

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 45
Respondent: Jeffrey Loiter

Request No. 45: Refer to page 4 of the Loiter Direct Testimony. Does Mr. Loiter agree that absolute least cost is not the standard by which CPCN applications are evaluated?

Response No. 45:

Beginning on line 30 of page 4, my testimony states that the Cooper unit 1 project is “an attempt to pursue the least cost means of retaining a portion of the Company’s generating capacity in isolation” based on the fact that EKPC’s own application repeatedly refers to the Cooper unit 1 project as purportedly the least cost option. I made no statements regarding the standards the Commission uses to evaluate CPCN applications.

Request No. 46: Refer to pages 6 through 12 of the Loiter Direct Testimony.

- a. Was Mr. Loiter retained by the Sierra Club to perform the analysis of EKPC's 2012 Integrated Resource Plan ("IRP") in Case No. 2012-00149?
- b. If he was not, did Mr. Loiter have access to the workpapers, analyses, evaluations, and other work product prepared by the Sierra Club experts in Case No. 2012-00149 or are his comments, observations, and criticisms in his testimony based solely on his own independent analysis of the Case No. 2012-00149 record?

Response No. 46:

- a. No.
- b. I did not have access to workpapers, analyses, evaluation, or other work product prepared by Sierra Club experts in Case No. 2012-00149 beyond that which is part of the public record.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 47
Respondent: Jeffrey Loiter

Request No 47: Refer to page 10 of the Loiter Direct Testimony, lines 1 through 3. Please provide a detailed listing of the specific jurisdictions to which Mr. Loiter refers and please provide a copy of the regulatory agency's orders and/or utility tariffs upon which Mr. Loiter's assertions are based.

Response No. 47:

Simplifying customer participation and providing “one-stop shopping” are among the best practice characteristics noted by ACEEE in their recent review of exemplary energy efficiency programs (<http://aceee.org/research-report/u132>). In particular, ACEEE noted a trend in exemplary programs where “customer-facing elements of the program are more comprehensive so that participants’ experience is less confusing and complicated. See for example the Mass Save® brand of energy efficiency programs offered by utilities in Massachusetts and Xcel Energy’s “One-Stop Efficiency Shop” program in Minnesota (<http://mncee.org/Find-Programs/One-Stop-Efficiency-Shop-Lighting-Retrofits/>).

Request No. 48: Refer to pages 12 and 13 of the Loiter Direct Testimony.

- a. The provided link to the American Council for an Energy-Efficient Economy ("ACEEE") State Energy Efficiency Scorecard is a single page document titled "2013 Spending Tables" and notes as the source document "2013 State Energy Efficiency Scorecard". Please explain in detail why Mr. Loiter only provided what appears to be a single page of the scorecard?
- b. On page 13, at lines 2 through 4, Mr. Loiter states "There is no reason why EKPC's programs should be limited to 0.15% each year for five years." Is this statement based solely on the comparison of the net incremental savings from electricity efficiency for the states listed on pages 12 and 13 of his direct testimony?
- c. According to the United States Energy Information Administration ("EIA"), its Electric Power Monthly report released on November 20, 2013, the average retail price of electricity to residential customers and all sectors for September 2013¹ was:
 - 1) Tennessee — 9.89 cents and 9.40 cents per kWh.
 - 2) North Carolina — 11.47 cents and 9.46 cents per kWh.
 - 3) Indiana — 11.10 cents and 8.72 cents per kWh.
 - 4) Ohio — 12.21 cents and 9.25 cents per kWh.
 - 5) Michigan — 14.99 cents and 11.06 cents per kWh.
 - 6) Kentucky — 9.94 cents and 7.89 cents per kWh.

Would Mr. Loiter agree that the average price of electricity would influence the success of any demand-side management or energy efficiency programs? Please explain the response in detail.

Response No. 48:

- a. The entire ACEEE scorecard is freely accessible at <http://aceee.org/research-report/e13k>.
- b. No.
- c. The average price of electricity is only one factor among many that would influence the success of efficiency programs. The total electric BILLS paid by utility customers are far more important to those customers than their per-kWh electric rates. EKPC's customers use far more electricity than the average household in the United States, so even at low rates, their total bills are comparable or even higher than average bills elsewhere. The table below shows average monthly bills for the states included in the question. As a further comparison, I have also included New England in this comparison, a region where rates are higher and efficiency programs typically achieve higher levels of savings. Monthly bills in Ohio and Indiana are roughly equal to those in Kentucky, but those states are achieving four to eight times the efficiency savings as planned by EKPC. Data are from

¹ http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt56a.

http://www.eia.gov/electricity/sales_revenue_price/xls/table5_a.xls

| State | Number of Customers | Average Monthly Consumption (kWh) | Average Price (cents/kWh) | Average Monthly Bill (\$) |
|----------------|----------------------------|--|----------------------------------|----------------------------------|
| Michigan | 4,250,620 | 676 | 14.13 | 95 |
| New England | 6,203,726 | 634 | 15.71 | 100 |
| Indiana | 2,755,595 | 997 | 10.53 | 105 |
| Ohio | 4,869,305 | 895 | 11.76 | 105 |
| Kentucky | 1,924,644 | 1,130 | 9.43 | 107 |
| North Carolina | 4,230,588 | 1,077 | 10.91 | 117 |
| Tennessee | 2,721,099 | 1,217 | 10.10 | 123 |

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 49
Respondent: Jeffrey Loiter

Request No. 49: Refer to pages 13 and 14 of the Loiter Direct Testimony. Please provide all workpapers, analyses, studies, assumptions, and other documentation utilized by Mr. Loiter to arrive at his estimated 2017 cumulative annual savings of 244,000 MWh and his estimated 2021 savings of 533,000 MWh.

Response No. 49:

See attached Excel workbook (“loads and resources final.xlsx”). The referenced values appear in cells H68 and L68 of the “analysis” worksheet, respectively.

Request No. 50: Refer to page 14 of the Loiter Direct Testimony, lines 12 through 31.

- a. Please explain in detail why it is reasonable for Mr. Loiter to add the summer peak reductions of 36 MW and 78 MW from the 2012 IRP to the currently planned 50 MW of summer peak reduction.
- b. Please provide all the calculations, assumptions, workpapers, and other documentation that supports Mr. Loiter's determination that \$1.7 million per year could produce a sustained additional 22 MW of summer peak demand reduction. Include with this response a detailed listing of the specific programs and activities that would produce the 22 MW reduction.
- c. Please provide all the calculations, assumptions, workpapers, and other documentation that supports Mr. Loiter's determination that in 2017 the total peak demand reduction would equal 58 MW. Include with this response a detailed listing of the specific programs and activities that would produce the 58 MW reduction.

Response No. 50:

- a. The summer peak reductions referenced on line 15 of page 14 are additive to the 50 MW reduction in the IRP because I assumed additional spending on efficiency above and beyond that which is contemplated/planned in the IRP.
- b. See attached Excel workbook ("loads and resources final.xlsx"). The referenced 22 MW summer peak reduction appears in cell E77 through Q77 of the "analysis" worksheet. My testimony identifies energy efficiency and demand response potential; it does not describe or advance a particular specific set of programs that could or should be used to achieve the potential identified.
- c. See attached Excel workbook ("loads and resources final.xlsx"), provided in response to EKPC Request No. 49. The referenced 58 MW summer peak reduction is the sum of the values in cells H70 and H77. My testimony identifies energy efficiency and demand response potential; it does not describe or advance a particular specific set of programs that could or should be used to achieve the potential identified.

KPSC Case No. 2013-00259
SC Response to EKPC Requests
Item No. 51
Respondent: Jeffrey Loiter

Request No. 51: Refer to page 16 of the Loiter Direct Testimony. In the previously referenced EIA Electric Power Monthly report, the average retail price of electricity for residential customers in New England for September 2013 was 17.40 cents per kWh and for all sectors was 15.07 cents per kWh. Would Mr. Loiter agree that the price of electricity in New England would significantly influence the success of any energy efficiency programs? Please explain the response in detail.

Response No. 51:

Please refer to the answer to question 48c. Also, note that the levels of efficiency savings in Massachusetts are six times the level of savings in my estimate and ten times what EKPC is proposing. To the extent that retail electric prices have an influence on efficiency potential, I do not believe that this impact is of similar magnitude.

Request No. 52: Refer to Exhibit JML-2 of the Loiter Direct Testimony.

- a. Was this study prepared at the request of any agency of the Commonwealth of Kentucky? If no, please identify the entities that requested the development of the "Technical Assistance Program — Energy Efficiency Cost-Effective Resource Assessment for Kentucky."
- b. Does Mr. Loiter have access to the workpapers, assumptions, analyses, and other documentation that support the evaluations and conclusions contained in Exhibit JML-2?
- c. Is Mr. Loiter prepared to make the authors of Exhibit JML-2 available for discovery or cross-examination if there are questions concerning the assumptions, evaluations, or conclusions contained in the report?
- d. The first page of the Executive Summary states that this assessment is the first of three documents that comprise the ACEEE's energy efficiency potential study for Kentucky. Please indicate when the remaining two documents are expected to be completed.

Response No. 52:

- a. I am not an author of Exhibit JML-2 nor was I involved in its production in any way. I have no knowledge of who requested the study beyond the organizations listed in the report itself: ACEEE, Oak Ridge National Laboratory, and the US Department of Energy.
- b. No.
- c. No.
- d. Attached is a document that may represent one of the two documents referenced in the potential study. I have no knowledge as to whether this in fact represents one of the referenced documents, nor any information on any other documents that might represent the referenced items.



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U.S. DEPARTMENT OF
ENERGY

Energy Efficiency &
Renewable Energy

Technical Assistance Program

**An Assessment of Utility Program Portfolios
in the Commonwealth of Kentucky**

June 14, 2012



OAK RIDGE NATIONAL LABORATORY
Managed by UT-Battelle for the Department of Energy

This work has been performed by the American Council for an Energy-Efficient Economy under the Contract No. 4200000341 with Oak Ridge National Laboratory, which is managed by UT-Battelle, LLC, under Contract with the US Department of Energy No. DE-AC05-00OR22725.

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Abstract

Some utilities in the Commonwealth have been funding demand-side management programs for decades despite the absence of a statutory requirement for energy efficiency requiring them to do so. This highlights a few encouraging signs. First, there is a fundamental understanding from utilities that energy efficiency is a low-cost resource that helps meet growing demand for energy, helping to reduce strain on the Commonwealth's energy system and delaying, or even negating, the need for investments in supply-side resources, such as generation facilities and transmission infrastructure. Second, regulatory policy codified in KRS 278.285 and designed to encourage utility investment in energy efficiency appears to be having some impact, though it is difficult to quantify the contribution. Finally, recent utility DSM filings exhibit utilities' continuing commitment to energy efficiency: although utilities are ramping up program budgets and savings at varying rates, there does not appear to be any danger of utilities rolling back their commitments.

The success of energy efficiency programs in the Commonwealth requires the commitment of all stakeholders, from consumers to program administrators to the Commonwealth's Public Service Commission. Utilities have already laid a solid foundation for future growth of their energy efficiency programs, but there is more work to do in consistently documenting the existence and performance of these programs. And, as found by a previous ACEEE assessment of the cost-effective energy efficiency resource potential available in the Commonwealth, significant savings from energy efficiency are yet to be captured by utility energy-efficiency programs. Ultimately, as the process of approving and evaluating energy efficiency programs becomes more efficient and effective, the marginal additional effort and costs could end up saving ratepayers in the Commonwealth considerable sums on their energy bills.

Executive Summary

BACKGROUND

This report is one of a series of assessments for the Commonwealth that is intended to provide stakeholders with a snapshot of existing state- and utility-financed energy efficiency efforts, and the potential energy efficiency resources available left to be captured by state and utility policies and programs. Prior to this report, ACEEE conducted an assessment of utility energy efficiency programs in other states to provide a benchmark with which to measure the effectiveness of utility programs in the Commonwealth (ACEEE 2011). ACEEE has also released an assessment of the cost-effective energy efficiency resource potential prior to this report (ACEEE 2012). These publications will be followed by two additional assessments: a program/policy analysis, which will focus on the degree to which programs and policies can capture the resource potential identified in the cost-effective resource assessment, and; a macroeconomic assessment, which will quantify the potential impacts of energy efficiency programs and policies on economic growth and employment in the Commonwealth.

INTRODUCTION

Assessing the performance of existing, utility-financed energy efficiency programs in the Commonwealth of Kentucky is critical to understanding lessons learned and how these programs

could be modified to perpetuate cost-effectiveness. By conducting a quantitative analysis of program savings, costs, and participation, we can evaluate program results reported by Kentucky's utilities and compare these results to similar program portfolios in other states to gauge the progress of energy efficiency programs in the Commonwealth. In addition, this report identifies important program design and regulatory issues that stakeholders in the Commonwealth should consider in order to raise the performance of utility energy efficiency programs.

This report assesses existing energy efficiency programs offered by Kentucky's three investor-owned utilities – Duke Energy Kentucky (Duke), Kentucky Power Company (KPC), and Louisville Gas and Electric Company/ Kentucky Utilities Company (LG&E/KU) – and one public power utility, the Tennessee Valley Authority (TVA), which together account for over 60% of retail electricity sales in the Commonwealth. We do not include municipal utilities because they are not regulated by the Kentucky Public Service Commission (KPSC). And though we include TVA, it is also not regulated by the KPSC. There are also no DSM program performance data available through the KPSC for jurisdictional cooperative corporations.

We review program metrics reported by these utilities for the 2008-2010 program years. Our analysis focuses on overall utility program portfolios as well as individual program performance, though we consider only electric energy efficiency programs. We use a number of metrics upon which to base our assessment, such as program electricity savings (as a percent of sales and absolute) and the levelized cost of saved energy (CSE). We gathered some data on program participation, but did not focus on program participation or savings per customer because of a lack of data for both total program participation and, to a much greater degree, the number of potentially eligible customers by customer class.

DISCUSSION

In this section we review the overall results from our analysis on utility program performance in the Commonwealth, using the results from a previous ACEEE analysis on utility energy efficiency programs as benchmarks for performance (see Table ES-1) (ACEEE 2011). Following the results, we highlight some important program design and regulatory issues that stakeholders in the Commonwealth should consider in order to improve the performance of its utility energy efficiency programs.

AVAILABLE DATA

In this section we briefly discuss the metrics reported by utilities to the KPSC that we use to inform our analysis of utility program portfolios in the Commonwealth. These are the metrics that we were able to find in various utility filings with the KPSC, the sources of which we reference in the table as well. We take this opportunity to highlight a number of caveats prior to delving into the analyses of the various portfolios.

We were only able to procure actual performance results for Duke Energy, Kentucky Power, and TVA's program portfolios. The metrics that we use for our analysis of LG&E/KU's program portfolio

are projections from their 2007 DSM plan filing; actual performance data for LG&E/KU's programs were unavailable.¹

- Duke reported energy savings (MWh), demand reductions (kW), program costs (\$) and program participation for the 2008, 2009, and 2010 program years.
- KPC reported energy savings (MWh), demand reductions (kW), program costs (\$) and program participation for the 2009, and 2010 program years.
- LG&E/KU reported *projections*, which included estimates of energy savings (MWh), demand reductions (kW), program costs (\$) and program participation. In the 2007 filing we referenced, this information was reported for the 2008-2014 program years.
- TVA made energy savings (MWh), demand reductions (kW), and program costs (\$) data available at the state level for the 2008, 2009, and 2010 program years. However, TVA did not include program participation. TVA does not report aggregate program data, by state, for its energy efficiency efforts to the KPSC because TVA and its distribution cooperatives are not under the KPSC's jurisdiction.
- Program performance data on jurisdictional cooperative corporations were not publically available for this analysis. .
- Municipal utilities are not under the jurisdiction of the KPSC and therefore are not required to report their energy efficiency efforts.

ASSESSMENT OF OVERALL RESULTS

In Table ES-1 and Figure ES-1 below we report the overall portfolio results for all utilities for the program years 2008-2010. The low savings percentages and high levelized CSE values are attributable to results from Kentucky Power Company's portfolio, which has not included programs for commercial or industrial customers since 2006. The percent savings take into account savings only from residential programs, which are compared to total sales across all sectors and, therefore, result in the relatively low percent savings. Nonetheless, utility energy efficiency programs in the Commonwealth have generally performed well compared to utilities in other states: performance results for Kentucky utilities fall within the ranges for non-Kentucky utilities that we report in Table ES-2.² This is despite the fact that, for decades, electric utilities in Kentucky have maintained some of the lowest electricity prices in the United States.³ Energy prices are one important market incentive for utility investment in energy efficiency programs, which likely has had some influence on the commitment of utilities in the Commonwealth to pursuing energy efficiency aggressively.⁴ Still, more

¹ LG&E/KU reported actual savings for several of their program years in a June 13, 2011 filing in its joint integrated resource plan docket, Case No. 2011-00140. No costs or data on participation were reported in this filing.

² See Sciortino et. al (2011a and 2011b) for additional reviews of energy savings performance by states and utilities.

³ Low energy prices do not guarantee low monthly energy bills for customers. The average residential energy bill in Kentucky (\$107) hovers just below the national average (\$110) (EIA 2011).

⁴ There are many other market forces that drive investment in energy efficiency programs, such as fuel costs, the age of generation facilities, the ability of existing capacity to meet future demand, customer demand for energy efficiency services, etc.

can be done. For example, in ACEEE's comparison of utility program performance from other states, utilities aggressively pursuing energy efficiency achieved incremental annual savings in the tens-of-thousands to hundreds-of-thousands of megawatt-hours (MWh), achieving close to or above 1% annual savings. These utilities also spent tens-of-millions of dollars to achieve those savings. But while program expenditures and savings in the Commonwealth are an order-of-magnitude lower than leading states, the energy savings generated by these programs are still being achieved cost-effectively.

This analysis does not capture any of the industrial sector's voluntary energy efficiency efforts. In Kentucky, the industrial sector is allowed to opt-out of participation in regulated DSM programs. With forty-eight percent of the electricity usage going to the industrial sector, percent-of-sales is a more reasonable metric to use to estimate and report savings if all sectors were participating in regulatory DSM programs.

Utilities in the Commonwealth have already laid a solid foundation of energy efficiency programs without being statutorily required to do so.⁵ They also have several decades of experience administering demand-side management (DSM) programs, so ramping up existing programs and adding new ones to their portfolios could be done by leveraging existing resources and infrastructure. This would require greater investment on behalf of utilities and consumers alike. But, as other states have shown, it is possible to generate much higher volumes of energy savings while maintaining the cost-effectiveness of energy efficiency programs. A previous ACEEE assessment of the cost-effective energy efficiency resource potential available in the Commonwealth shows that there are considerable savings from energy efficiency yet to be captured by utility energy-efficiency programs. With this available potential and the ability of utilities to leverage existing demand-side management infrastructure, utilities in the Commonwealth are in a position to augment their energy efficiency portfolios successfully and for the benefit of all customer classes.

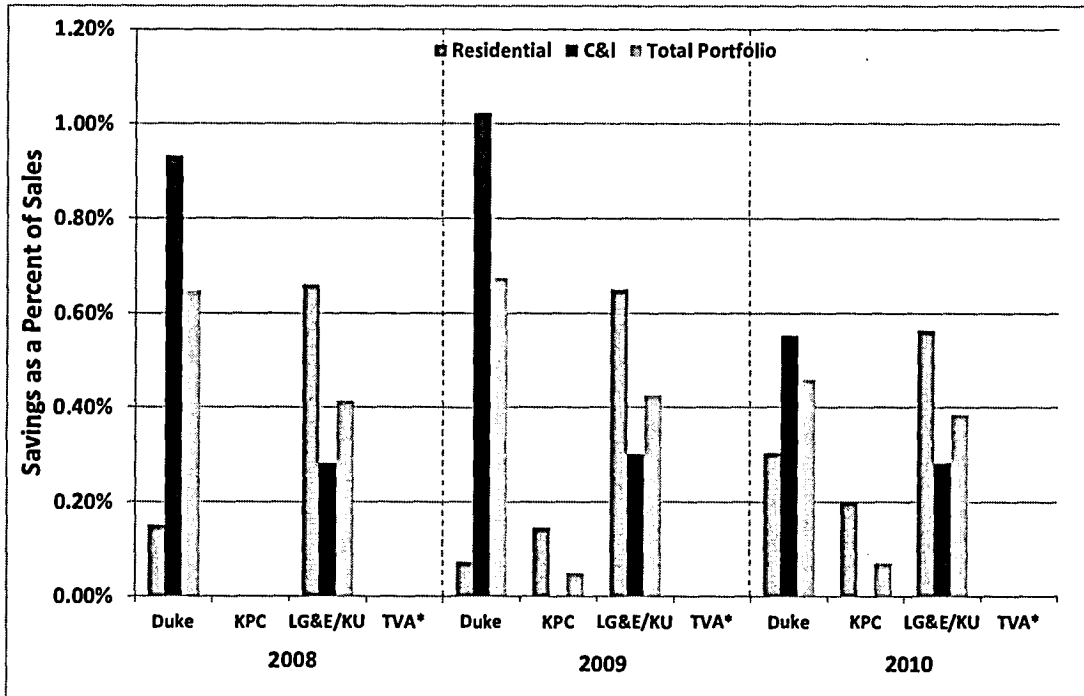
Table ES-1. Range of Portfolio Results from Non-Kentucky & Kentucky Utility Program Analysis

| Portfolio Results | | | | |
|---------------------------------------|-----------------------------------|-------------------------------|-------------------------------------|------------------------------------|
| Program Year | % Savings (of total sales) | Levelized CSE (\$/kWh) | Average Cost of Saved Energy | Median Cost of Saved Energy |
| Non-Kentucky Portfolio Results | | | | |
| 2009 | 0.04% - 1.06% | \$0.005 - \$0.024 | \$0.015 | \$0.013 |
| 2010 | 0.16% - 1.48% | \$0.006 - \$0.018 | \$0.010 | \$0.009 |
| Kentucky Portfolio Results | | | | |
| 2008 | 0.41% - 0.65% | \$0.005 - \$0.022 | \$0.013 | \$0.013 |
| 2009 | 0.05% - 0.67% | \$0.007 - \$0.039 | \$0.022 | \$0.020 |
| 2010 | 0.07% - 0.46% | \$0.010 - \$0.042 | \$0.022 | \$0.019 |

Source of Non-Kentucky Portfolio Results: ACEEE 2011

⁵ While jurisdictional utilities are not required to offer energy efficiency programs, 807 KAR 5:058 requires utilities to summarize resource acquisitions in their integrated resource plans, including demand-side management programs.

Figure ES-1. Electricity Savings as % of Sales, by Sector (2008-2010)



* Retail electricity sales data for TVA's KY operations were unavailable, so we were unable to estimate percentage values for TVA.

INTERPRETING THE RESULTS

The utility program portfolios we have reviewed differ from one another as well as from those in other states on a number of factors: the types and number of programs that are offered; the volume of savings they achieve; and the cost of achieving those savings. There are countless reasons why this may be the case. In general, the degree to which energy efficiency is pursued is largely influenced by the utility regulatory environment in which utilities operate. Utility leaders in generating savings from energy efficiency generally are those operating in states with aggressive energy efficiency goals. Utilities are unlikely to make substantial investments pursuing demand-side resources if they are unable to benefit in a manner similar to making investments in supply-side resources.

The primary impetus for significant utility investment in energy efficiency is usually a mandate from the utility regulatory body or the state legislature requiring utilities to meet annual savings targets, usually referred to as an Energy Efficiency Resource Standard (EERS). So it is no coincidence that utility leaders in energy efficiency are those operating in states with aggressive energy efficiency goals (see Sciortino 2011b). The KPSC does not have the statutory authority to set savings targets; however, KRS 278.285 establishes regulatory policies that, in the absence of statutory requirements, provide some motivation for utilities to invest in energy efficiency programs, through "adders" in the DSM surcharge on customer energy bills.

The regulatory motivation for jurisdictional utilities in the Commonwealth to design and implement energy efficiency programs, such as program cost recovery and performance incentives, was codified by Kentucky Revised Statutes (KRS) 278.285 in 1994. Utilities differ in the extent to which they take

advantage of these motivational tools, however. Program costs incurred as a result of using these tools are incorporated, or “added,” into the DSM surcharge that appears on the customer energy bill, allowing the utility to recover energy efficiency program costs in addition to some additional financial incentives. The amount of the DSM surcharge is determined by five elements: direct DSM program costs; projected lost sales revenues as a result of the programs; an incentive designed to provide positive financial rewards to a utility to encourage DSM implementation; capital recovery; and a true-up from the previous filing. While these “adders” serve to encourage greater investment in utility energy efficiency programs, ultimately they can also increase the total cost of delivering the programs to the customer.⁶

Using portfolio-level data reported by utilities in the Commonwealth to the U.S. Department of Energy’s Energy Information Administration (EIA) through Form 861, it is evident that DSM expenditures have trended upwards for the all three major IOUs since 2001 (EIA 2010b).⁷ While overall savings fell around the time of the recession, they have been steadily rising over the last several years. Clearly, then, existing regulatory policy encouraging investment in energy efficiency programs has had some impact on utility investments.

REGULATORY MECHANISMS TO FACILITATE PROGRAM REPORTING, DATA ACCESSIBILITY AND TRANSPARENCY

From our review of utility program portfolios in the Commonwealth, we identified a few regulatory areas that, if addressed, would facilitate the growth and success of energy efficiency programs significantly.

First, neither the Kentucky Public Service Commission nor the State Legislature has established orders or laws outlining reporting requirements for utility DSM programs that apply to all utilities.⁸ As a result, the structure of utility DSM status reports is inconsistent and the content disparate and inaccessible. Rigorously documenting the impacts of DSM programs is imperative if utilities, regulatory staff, and other stakeholders are to understand program performance and make justifiable decisions on how programs should be modified over time in order to perpetuate energy savings and ensure cost-effectiveness. Requiring greater consistency, clarity, and accessibility in the DSM status reports filed by utilities under their purview can provide value to all parties. By focusing on these

⁶ The effect of these adders on the overall cost-effectiveness to the customer is generally modest. The cost-effectiveness of a program is often measured over its life, which requires an avoided cost forecast in order to estimate its net present value of costs and benefits (avoided electricity costs for customers, for example) over that time period. Avoided costs generally increase over time due to a number of factors (such as capacity and infrastructure investments), but the relative effect of DSM program cost recovery on that overall increase is small. DSM surcharges are measured in mills, or 1/1000 of a dollar (per kWh), so any increase in retail prices – and, thus, energy bills – caused by the recovery of program costs will comprise a small percentage of a customer’s total energy bill. Still, while rates may increase in the short-term because less electricity is sold, total customer bills will decline due to savings from efficiency.

⁷ It is important to note that DSM program/portfolio performance data stretching back to 2001 is not readily available through the KPSC. Additionally, the EIA data do not disaggregate portfolio performance data to the program level.

⁸ The KPSC has issued at least one order requiring one of the utilities under its purview to file DSM status reports. We are uncertain if other orders for individual utilities have been issued.

criteria and codifying the types of information that must be included in reports, it will be much easier to track program and portfolio performance over time, which will allow analysts and stakeholders to make more informed decisions on program design.

Second, some of the Commonwealth's electric cooperatives have been operating DSM programs for which tariffs (i.e., surcharges on a customer bill to help pay for DSM programs) do not exist (some for over 20 years). In other words, there are DSM programs that are not supported by a DSM tariff, which would set forth the eligibility, charges, payments, and terms and conditions of the programs. Since the paramount concern of any state utility commission is to ensure just and reasonable rates for consumers, it is necessary that a commission reviews and keeps records of all DSM programs operated by utilities under its purview. This discrepancy was identified in November 2011 and has since been resolved. Regardless of the extent to which programs were undocumented, consumers in the Commonwealth have a statutory right to know where their money is being directed and, thus, utilities (regulated by the Commission) are statutorily required to "[...] submit tariffs that set forth the eligibility, charges, payments, and terms and conditions for each untariffed DSM program" and that, "Upon filing, the tariffs will be reviewed, solely to ensure that they comply with Commission statutes and regulations" (KPSC 2011).

Background

This report is one of a series of assessments for the Commonwealth that is intended to provide stakeholders with a snapshot of existing utility-financed energy efficiency efforts, and the potential energy efficiency resources available left to be captured by state and utility policies and programs. Prior to this report, ACEEE conducted an assessment of utility energy efficiency programs in other states to provide a benchmark with which to measure the effectiveness of utility programs in the Commonwealth (ACEEE 2011). ACEEE has also released an assessment of the cost-effective energy efficiency resource potential prior to this report (ACEEE 2012). These publications will be followed by two additional assessments:

- A program/policy analysis, which will focus on the degree to which programs and policies can capture the resource potential identified in the cost-effective resource assessment, and;
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Introduction

Assessing the performance of existing, utility-financed energy efficiency programs in the Commonwealth of Kentucky is critical to understanding lessons learned and how these programs could be modified to perpetuate cost-effectiveness. By conducting a quantitative analysis of program savings, costs, and participation, we can evaluate program results reported by Kentucky's utilities and compare these results to similar program portfolios in other states to gauge the progress of energy efficiency programs in the Commonwealth. We also discuss some important program design and regulatory issues that stakeholders in the Commonwealth should consider in order to raise the performance of utility energy efficiency programs.

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- What are some of the most successful programs?
- Are the programs delivering savings cost-effectively?
- What are the total costs and savings of these programs and how do they compare to similar programs offered by utilities in other states?
- Are there additional programs and/or products that utilities should target in the future?

Our analysis focuses on electric energy efficiency programs only. While some portfolios we review in this document include programs for both electricity and natural gas, we concentrate on electric efficiency programs because: the number of these programs far exceed those for gas; utility regulatory commissions generally require more comprehensive suites of program offerings for electric utilities; and more robust evaluation data is available from electric programs than from natural gas programs.

Energy Efficiency Programs in Context

Utilities across the nation have been offering energy efficiency programs to their customers for varying periods of time – some for decades, others have begun only in the last several years. The impetus for program development and implementation across utilities and over time has also varied – economics, regulatory policies, system reliability concerns, market competition, and rate impacts are factors that typically influence utilities in the number and scope of programs that they offer. Understanding when and why utilities cultivate their program portfolios gives insight into how the various programs perform and grow, allowing utilities to make informed decisions that will help ensure greater success with their portfolios.

A defining moment in the era of utility efficiency programs was the wave of energy market deregulation that spread across many states during the 1990s. In order to foster competition between utilities, some states began deregulating energy markets in the hopes that greater competition between utilities would generate greater customer benefits, such as lower customer energy rates. In the race for market share, however, utilities in many states quit investing in energy efficiency programs altogether because the administration costs cut into their revenues – costs that utilities were previously able to recover through regulatory mechanisms.

The foray into market deregulation proved largely unsuccessful. As a result, regulators have been looking to other measures to control consumer costs, such as investments in energy efficiency. Thus we have seen the number and efficacy of energy efficiency programs grow significantly over the last several years. Much of this growth can be attributed to utility regulatory policy and, to a lesser degree, legislative mandates, particularly due to the introduction of Energy Efficiency Resource Standards (EERS) in over half of the states in the nation. It is no surprise that utilities with the most comprehensive and effective program portfolios, as well as the most detailed reporting of program performance, are utilities in markets with an EERS that, importantly, have also developed complementary utility regulatory policies to facilitate investment in energy efficiency programs.

UTILITY PROGRAM PORTFOLIOS

Our analysis focuses on utility program portfolios as a whole as well as individual program performance, though we report data on the latter only in Appendix A. We collected and analyzed data for many individual programs in order to determine their effectiveness and the effectiveness of utility program portfolios overall. However, data at the individual program level can be inconsistent or difficult to compare to other programs, while aggregate portfolio results are more consistently comparable. Programs vary considerably in the way they are designed and marketed, and to the extent to which customers are incented to participate. So it is important to understand that, when comparing programs across utilities within the Commonwealth, variations in performance of seemingly similar

programs are a result of a number of factors that are not necessarily quantifiable. Comparing utility achievements based on overall portfolio performance, then, is a high-level but more reasonable method.

Assessing individual program performance is important; however, its importance is greater for program administration than it is for making comparisons of similar programs across portfolios. This is because program portfolios differ significantly not only across states, but also between utilities within the same state as well as within one utility that operates in several states. Furthermore, programs that may appear similar can also differ significantly with regards to many economic and administrative factors that affect program performance: utility investment, program marketing, program incentives (rebates, tax breaks), availability of trained/qualified contractors, and energy prices and demand are just a few examples.

ANALYTIC APPROACH

In evaluating utility energy efficiency programs, there are a number of metrics that are widely used to determine program and portfolio effectiveness. Below we discuss several of the most common metrics, which we use in our portfolio assessments later on. The key for any metric is providing some sort of normalization so that comparisons can be made across portfolios from utilities of various sizes and regions of the country. This list is not conclusive.

Savings (kWh) – This metric reports the volume of energy savings generated by a program/portfolio from its installed energy-efficient measures, such as lighting. Savings are reported either as “incremental”, or the volume of savings generated in year X by measures installed in year X, or as “cumulative”, or the volume of savings generated in years X, Y, and Z by measures installed in years X, Y, and Z. Often utilities report both incremental and cumulative energy savings in their DSM filings, as the latter is important in assessing progress over the life of a program/portfolio.

In addition to differentiating between incremental and cumulative savings, utilities also differentiate between “net” and “gross” savings. Gross savings include all the energy savings generated by measures installed through an efficiency program. Net energy savings subtract from gross savings the savings generated by “freeriders”, or program participants that would have installed energy-efficient measures even in the absence of a utility program. Hence, “net” savings. The reason for the differentiation is to ascertain the influence of program design (marketing, education, incentives) on participants who are less savvy – or totally unfamiliar – about energy efficiency than others. These are the utility customers that are most important to reach because, without efforts on the part of a utility to incent and encourage investment in energy efficiency, these customers are unlikely to do so.

Savings as a Percent of Sales – This metric calculates the volume of energy savings generated by a program/portfolio relative to a utility’s annual retail sales, reported as a percentage. Annual sales are taken from data reported by the Energy Information Administration (EIA 2009, 2010, and 2011). By normalizing the savings relative to a utility’s annual sales, differences in utility market share are taken into account, allowing comparisons of programs between utilities of different sizes. As a result, this metric is an invaluable indicator to evaluate a utility’s overall efforts in developing and implementing efficiency programs. Portfolios with higher percent savings can therefore be said to offer programs

that are well-funded, prudently marketed, and rigorously administered. It is important to note that the program savings considered in this metric are incremental, new savings; in other words, the savings are unique to that program year rather than the accumulation of savings from past program years.

It is important to understand, however, that this metric is not perfect, despite its usefulness in comparing program portfolios. Utilities use different methodologies for determining program savings and often report savings of different types (net versus gross savings). For utilities in Kentucky, it is not always clear which type of savings are being reported. Additionally, utilities use different methods for estimating savings of individual measures installed through a program. For example, some utilities rely on “deemed savings”, which provides ex ante savings measurements for individual products and equipment (a massive document listing hundreds of measures with pre-verified savings and costs, filed with a state’s regulatory commission). A program’s savings are then calculated by taking the number of installed measures and multiplying by their individual per unit savings. A more rigorous approach would be to measure savings impacts ex post through evaluation, measurement, and verification (EM&V). EM&V can be costly and time consuming, however, so many utilities tend to rely on deemed savings, at least for a portion of their portfolio. The benefit of measuring savings ex post through EM&V is that it takes into account variations in the quality of installation. Equipment can often be installed poorly, thereby preventing that equipment from performing at peak levels and generating savings on par with its deemed savings.

Experience in other states provides a benchmark with which to ascertain the range of percent savings that is indicative of a strong program portfolio. ACEEE’s 2011 State Efficiency Scorecard reported that the utilities in the top ten states are achieving annual incremental savings between 0.7% and 2.6% of annual retail sales. The next tier of ten states is achieving annual incremental savings between 0.4% and 0.7% (Scirotino et. al, 2011a). Utilities in states that are achieving the highest savings have had years of experience running energy efficiency programs. It generally takes several years of planning, development, and implementation for utilities to begin to generating savings on par with the leaders.

This analysis does not capture any of the industrial sector’s voluntary energy efficiency efforts. In Kentucky, the industrial sector is allowed to opt-out of participation in regulated DSM programs. With forty-eight percent of the electricity usage going to the industrial sector, percent-of-sales is a more reasonable metric to use to estimate and report savings if all sectors were participating in regulatory DSM programs.

Costs (\$) – When a utility reports program costs, it is reporting the total investment required on its part in order to bring a program to market. This includes costs incurred for program development and design, administration, marketing, education, training/payments to contractors (who perform the services), product purchases, incentives/rebates, and ex post program evaluation, measurement and verification. Program costs only capture the expense to deliver a program and do not include other elements that comprise the overall DSM surcharge. Additionally, participant costs are not included, i.e. the level of investment borne by the participant, which is the difference between the total cost of a measure, such as an efficient air conditioning unit, and the value of the utility rebate for that measure.

The absolute level of utility investment in a program/portfolio alone is not necessarily an illustrative metric to use in measuring a utility's commitment to energy efficiency, unless it is used as a reference to past or future utility portfolio investments to highlight trends. To facilitate comparisons across utilities, program costs must be indexed in some way in order to account for variations in the size of a utility. For instance, ACEEE reports utility energy efficiency spending as a percent of revenues in order to make comparisons across states in its annual State Energy Efficiency Scorecard.

Levelized Cost of Saved Energy (\$/kWh) – The levelized cost of saved energy (CSE) is defined as the level of payment necessary each year to recover the total investment and interest payments (at a specified interest rate) over the life of an efficiency measure or in the case of energy efficiency programs, over the average life of all the measures installed through a program. The levelized CSE is essentially a measure of the “bang for the buck,” or the volume of savings achieved with each dollar of program investment: the lower the CSE, the greater savings being generated per dollar. This methodology is an exercise in normalization that allows utilities to compare energy efficiency with other generation resources to evaluate the relative cost-effectiveness over their lifetimes and is usually reported in dollars per kilowatt-hour. For example, if the total cost of a pulverized coal plant is around \$0.08 per kWh but a utility can generate energy savings through efficiency programs at a rate of \$0.03 per kWh, then energy efficiency is the more cost-effective resource for meeting electricity demand

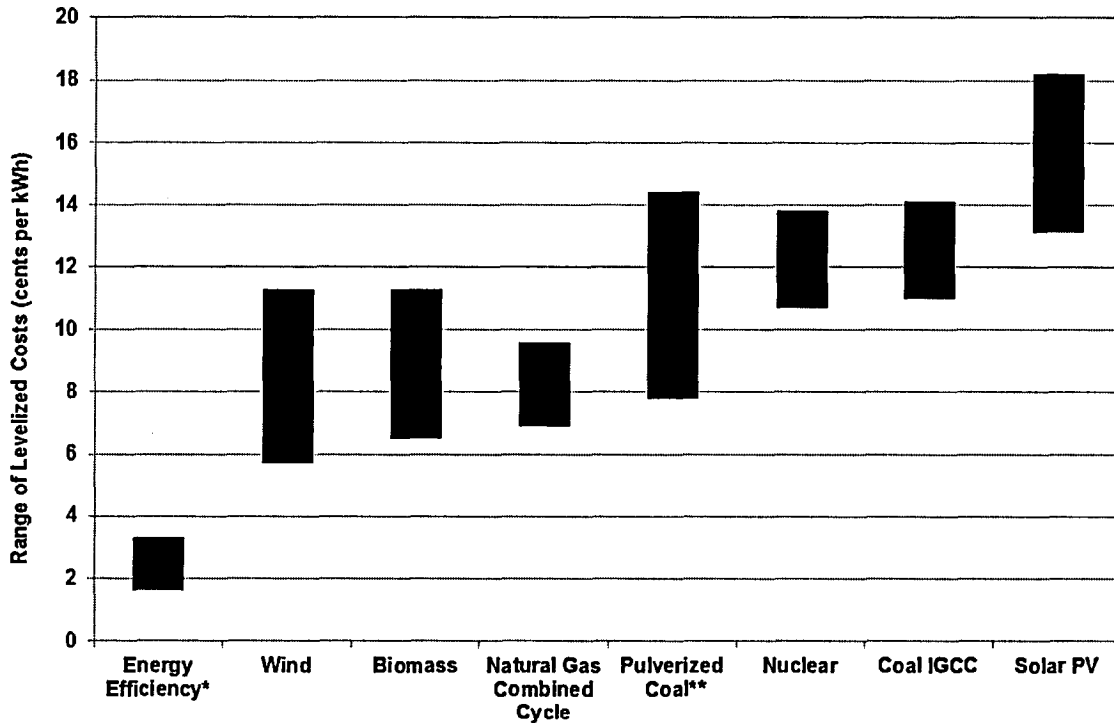
CSE values in this report are calculated by ACEEE using data reported by utilities. To estimate the levelized cost of saved energy we discount program investments at a rate of seven percent over the life of a measure, or, in the case of programs and portfolios, over the average life of all installed measures in a program. This gives us the present value (cost) of the investments. We then divide by the volume of savings achieved through a particular program, which gives us the cost of achieving each kilowatt-hour of saved energy, in \$/kWh.

There are a number of ways to measure the costs (and benefits) of energy efficiency programs, which focus on either the customer or utility perspective, or both. Figure 1 represents costs from a program administrator (utility) perspective. This is known as the utility cost or program administrators cost (PAC) test. This is a cost/benefit test that measures the net costs of a program based on the costs incurred by the utility (including incentive costs) and excluding any net costs incurred by the participant (customer). The costs used to determine the portfolio results we report below are from the utility perspective, so they do not include customer costs. The benefits for this test are the avoided supply costs of energy and demand; the costs are the program costs incurred by the utility, incentives paid to the customer, and any increased supply costs. The other test frequently utilized is the total resource cost (TRC) test. Regulators sometimes implement TRC inconsistently, however, which makes comparisons between states difficult. The TRC benefit/cost test includes both the participants' and the utility's costs. The benefits are avoided energy supply costs; the costs are the program costs (including equipment costs) paid by the utility and the participants, plus the increase in supply costs for any period in which load has been increased.

In a 2009 analysis, ACEEE found that the energy efficiency programs for utilities across 14 states have portfolios performing at a levelized CSE ranging from \$0.016 to \$0.033 per kWh, with an average cost

of \$0.025 per kWh (Friedrich et al, 2009). At these levels, energy efficiency is the least costly energy resource option available for utility resource portfolios: saving a kWh through energy efficiency is around one-third or less the cost of any new source of electricity supply (see Figure 1).

Figure 1. Levelized Utility Cost of New Electricity Resources



Notes: *Energy efficiency data from Friedrich et al. 2009 (ACEEE), which represents 5 years of average utility efficiency program cost data from 12 states. All other data from Lazard (2009).

**High-end range of advanced pulverized coal includes 90% carbon capture and storage.

The 2009 ACEEE study assumes an average measure lifespan of 10-15 years for electricity programs, with a median of 13 years, which were reported by utilities for their energy efficiency program portfolios in a given program year. Unfortunately, the program portfolios that we reviewed for the current study did not consistently report average measure lives. Therefore, we used the 10-15 year range from the 2009 study to estimate a range of levelized CSEs for each utility's portfolio in each program year. For each utility, tabular results are only reported assuming the median value of 13 years. Appendix A provides tables by utility that include the full range of levelized CSEs for each program in a utility's portfolio.

Program Participation (%) – Program participation is a measure of the market share reached by a program. Occasionally participation is expressed as a percentage relative to the number of potentially eligible customers. Few utilities report program participation as a percentage, however, if they report program participation at all. Instead, they focus only on the number of actual program participants. For some programs, one could assume that the total number of customers in a sector (residential, commercial, industrial) is equivalent to the total number of potential customers. But well-designed programs target particular market segments within a sector, such as low-income customers or small

commercial operations, so this assumption is not an accurate reflection of potential market participation. Additionally, many utilities measure program participation based on the number of installed efficiency measures, such as compact fluorescent lights or central air-conditioning tune-ups, as opposed to the number of households or firms.

Increasing overall program savings cannot be accomplished cost-effectively simply by expanding participation in existing programs. So while this metric is another useful tool in the program analysis kit, program performance should not be measured based on participation alone. Ultimately, good program design maximizes the volume of savings generated per customer. This generally means customers must install more energy efficiency measures with greater incremental efficiency gains to achieve deep savings. In states with more robust efficiency programs, program administrators are augmenting customer participation through better advertising (targeting social media), greater convenience (minimizing administrative costs), and higher incentives, the latter of which can potentially backfire if funding is not adequate enough to meet demand. Friedrich et al. (2009), for example, found that program incentives average around 75% of total program costs and range between 60 and 90% of total program costs.

We do not focus on program participation or report savings per customer in this assessment because of a lack of data for both total program participation and, to a much greater degree, the number of potentially eligible customers by customer class. As a measure of program performance, reporting customer participation either as a percentage of potential customers or in terms of savings per customer is a valuable indicator that utilities must strive to document in their program assessments. Comparing these numbers over time illustrates the progress of a program and gives administrators another metric with which to determine the tenets of a program that are in need of adjustment.

Utility Program Assessments

This section of the report reviews the program portfolios of Kentucky's three electric investor-owned utilities and TVA, which have varying degrees of experience administering energy efficiency programs. For each utility, we first give a brief discussion of its history with energy efficiency, followed by a description of existing programs and an assessment of program performance based on publicly available data acquired through the KPSC.

It is important to add some additional context for the evaluation of utility energy efficiency portfolios in the Commonwealth. Utility-funded energy efficiency programs are not mandatory in Kentucky; participation on the part of utilities is voluntary. The KPSC only retains the authority to "determine the reasonableness of demand-side management plans proposed by any utility under its jurisdiction", as codified in KRS 278.285. One such factor in making this determination is "the cost and benefit analysis" of the DSM programs. Furthermore, KRS 278.285 (3) states that industrial customers with energy intensive processes are exempt from paying for utility demand-side management programs through their rates and, instead, may implement cost-effective DSM measures on their own.

In Table 1 we report the range of portfolio results from a previous ACEEE assessment of utility programs in ten other states, such as Arkansas, Iowa, and Pennsylvania (ACEEE 2011). In addition, in Table 2 we report the range of levelized cost of saved energy estimated in that assessment. We use

these results as a benchmark through which to assess portfolio and program performance for Kentucky’s utilities. The results cover program years between 2008 and 2010, though we only reported results for any two program years, either 2008-2009 or 2009-2010, in order to show how programs matured over the course of two years.

Table 1. Range of Portfolio Results from Non-Kentucky Utility Program Assessment

| Portfolio Results | | | | |
|-------------------|----------------------------|------------------------|------------------------------|-----------------------------|
| Program Year | % Savings (of total sales) | Levelized CSE (\$/kWh) | Average Cost of Saved Energy | Median Cost of Saved Energy |
| Year One | 0.04% - 1.06% | \$0.005 - \$0.024 | \$0.015 | \$0.013 |
| Year Two | 0.16% - 1.48% | \$0.006 - \$0.018 | \$0.010 | \$0.009 |

Source: ACEEE 2011

Table 2. Range of Levelized CSE (\$/kWh), Program Years One & Two

| | Year 1 | Year 2 |
|-----------------|-------------------|-------------------|
| 10 Years | \$0.006 - \$0.029 | \$0.007 - \$0.022 |
| 13 Years | \$0.005 - \$0.024 | \$0.006 - \$0.018 |
| 15 Years | \$0.004 - \$0.021 | \$0.005 - \$0.016 |

Source: ACEEE 2011

Again, the metrics we consider are savings as a percent of sales and the levelized cost of saved energy for program portfolios, not for individual programs (see Appendix A for results by program). Data on program participation was too scant to allow for consistent comparisons across utilities.

AVAILABLE DATA

In this section we briefly discuss the metrics reported by utilities to the KPSC that we use to inform our analysis of utility program portfolios in the Commonwealth. These are the metrics that we were able to find in various utility filings with the KPSC, the sources of which we reference in the table as well. We take this opportunity to highlight a number of caveats prior to delving into the analyses of the various portfolios.

We were only able to procure actual performance results for Duke Energy, Kentucky Power, and TVA’s program portfolios. The metrics that we use for our analysis of LG&E/KU’s program portfolio are projections from their 2007 DSM plan filing; actual performance data for LG&E/KU’s programs were unavailable.⁹

- Duke reported energy savings (MWh), demand reductions (kW), program costs (\$) and program participation for the 2008, 2009, and 2010 program years (Duke 2008, 2009, and 2010).

⁹ LG&E/KU reported actual savings for several of their program years in a June 13, 2011 filing in its joint integrated resource plan docket, Case No. 2011-00140. No costs or data on participation were reported in this filing.

- KPC reported energy savings (MWh), demand reductions (kW), program costs (\$) and program participation for the 2009, and 2010 program years (KPC 2011).
- LG&E/KU reported *projections*, which included estimates of energy savings (MWh), demand reductions (kW), program costs (\$) and program participation. In the 2007 filing we referenced, this information was reported for the 2008-2014 program years (LG&E/KU 2007).
- TVA made energy savings (MWh), demand reductions (kW), and program costs (\$) data available at the state level for the 2008, 2009, and 2010 program years. However, TVA did not include program participation. TVA does not report aggregate program data, by state, for its energy efficiency efforts to the KPSC because TVA and its distribution cooperatives are not under the KPSC's jurisdiction.
- Program performance data on jurisdictional cooperative corporations were not publically available for this analysis.
- Municipal utilities are not under the jurisdiction of the KPSC and therefore are not required to report their energy efficiency efforts.

Duke Energy Kentucky

Background

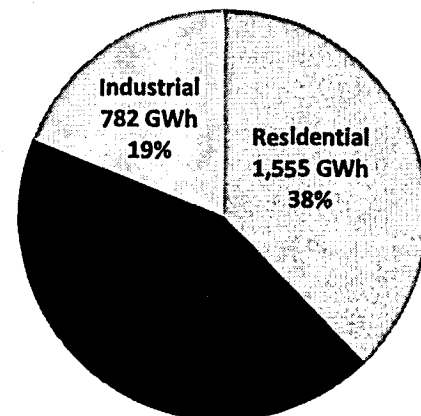
Duke Energy Kentucky has been offering DSM programs to its customers since 1996. Duke regularly convenes a multi-party collaborative, which includes representatives from the state government and various nonprofits, to review and approve its residential and commercial and industrial portfolios prior to filing the DSM application with the KPSC.

Program Portfolio

Currently Duke's program portfolio consists of a dozen energy efficiency programs for its residential, commercial and industrial customers. This does not include load management programs such as its Power Manager or Power Share programs. Duke's portfolio is fairly diverse. Its residential portfolio includes programs such as low-income weatherization, refrigerator recycling and replacement, home energy audits and retrofits, and personalized energy reports. Its commercial and industrial portfolio includes programs that provide rebates for energy efficient lighting, HVAC equipment, and motors, plus an incentive program for public schools. With years of experience and a broad set of energy efficiency programs, Duke has established itself as a leader in energy efficiency in the Commonwealth. Despite a decrease in its portfolio savings by over 50% during the 2011 program year due to falling participation for some programs, Duke has led utilities in Kentucky in generating savings from energy efficiency since 2008. And it has done so while offering programs that are, for the most part, cost-effective.

Most of Duke's energy efficiency programs focus on equipment replacement – with the exception of its energy efficiency website and personalized energy report programs – which requires providing rebates to customers in order to buy-down the initial costs of efficient equipment. Duke does not

Figure 2. Duke 2010 Sales



Source: EIA 2011

disaggregate its program costs by type in its status reports, so we have no data on incentives to reference, but incentive levels are likely relatively high for its two low-income programs, which are reflected in the relatively high levelized cost of saved energy for these programs (see Table A-1 in Appendix A for program results).

Assessment of Results

At the portfolio level, Duke has been generating significant savings with its programs since 2008, with the exception of its residential portfolio during the 2009 program year. The high CSE for its residential portfolio is largely driven by the high CSE of its two low-income programs. Residential low-income programs, in general, are rarely cost-effective because utilities tend to keep participant costs close to zero. In other words, utilities tend to provide rebates equivalent to 100% of the up-front costs of energy efficiency measures installed through the program because low-income customers often reside in very inefficient housing, yet do not have the income to invest in upgrades themselves.

Duke's commercial and industrial (C&I) program portfolio has been performing well since 2008. The services Duke offers to its C&I customers cover the major end-uses in commercial buildings (such as lighting, heating, and cooling) and motors. The levelized CSE of the portfolio falls within the range identified in Tables 1 and 2 above and, in fact, lies towards the lower end of that range. In addition, as a percent of total electricity sales, the savings generated by Duke's C&I programs in 2008 and 2009 are well towards the upper-end of the range of savings reported in Table 2.

While Duke's residential program portfolio has not been delivering savings to the degree of its C&I portfolio, it is important to understand that residential programs are often less cost-effective relative to C&I programs; however, residential programs are typically delivered cost-effectively. Low-income efficiency programs play a major role in this disparity, due to the relatively high incentive levels required to garner customer participation. In general residential customers are less inclined to pay the high up-front costs required for deep retrofits – i.e., whole-home retrofits as opposed to equipment replacement – and therefore require greater incentives to do so than commercial customers. Residential customers also do not benefit from the economies of scale that are more prevalent in the commercial sector.

Duke reported detailed data on program participation. With this data we were able to ascertain trends in participation over time. It is clear from this data that the number of participants in Duke's residential programs also played a major role in the performance of its programs. The number of participants dropped considerably in 2009, which had a noticeable impact on savings, although program costs were actually higher in the 2009 program year compared with 2008.

The majority of savings generated in both portfolios comes from residential and C&I lighting programs (see Table A-1 in Appendix A), although savings from lighting, largely residential, have dropped noticeably in recent years. Neither Duke's residential nor C&I portfolio offers programs targeting new construction. And while Duke's residential portfolio is diverse, its commercial portfolio would benefit greatly from targeting additional areas beyond equipment replacement, such as computer efficiency and systems and controls (building operations).

Table 3. Results for Duke Energy Kentucky's Energy Efficiency Portfolio

| Program | Program Year | Partic. [*] | Retail Sales | Savings (of total sales) | Net Savings | Costs | Levelized CSE (\$/kWh) |
|---------------------------|--------------|----------------------|--------------|--------------------------|---------------|----------------|------------------------|
| | | | GWh | % | MWh | Million \$ | 13 yrs |
| Residential | 2008 | 45,111 | 1,473 | 0.15% | 2,224 | \$ 0.77 | \$ 0.04 |
| C&I | | 27,465 | 2,569 | 0.93% | 23,913 | \$ 0.44 | \$ 0.002 |
| Total All Programs | | 72,576 | 4,041 | 0.65% | 26,137 | \$ 1.21 | \$ 0.005 |
| Residential | 2009 | 11,794 | 1,404 | 0.07% | 1,017 | \$ 0.89 | \$ 0.09 |
| C&I | | 47,089 | 2,434 | 1.02% | 24,867 | \$ 0.86 | \$ 0.004 |
| Total All Programs | | 58,883 | 3,838 | 0.67% | 25,884 | \$ 1.74 | \$ 0.01 |
| Residential | 2010 | 37,475 | 1,555 | 0.30% | 4,723 | \$ 1.00 | \$ 0.02 |
| C&I | | 29,715 | 2,562 | 0.55% | 14,155 | \$ 0.72 | \$ 0.01 |
| Total All Programs | | 67,190 | 4,117 | 0.46% | 18,877 | \$ 1.72 | \$ 0.01 |
| Residential | 2011 | 18,236 | - | - | 2,357 | \$ 1.16 | \$ 0.05 |
| C&I | | 25,537 | - | - | 5,423 | \$ 0.38 | \$ 0.01 |
| Total All Programs | | 43,773 | - | - | 7,779 | \$ 1.53 | \$ 0.02 |

Sources: Duke 2008, 2009, 2010, and 2011; EIA 2011, 2010a, and 2009

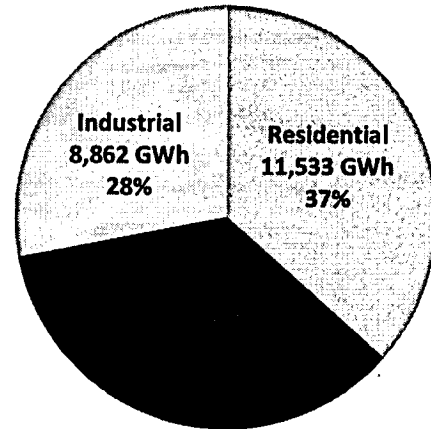
* Values for the lighting programs, both residential and C&I, are given in terms of units, not participants. So these values include both number of participating households and number of installed lighting units.

Louisville Gas & Electric and Kentucky Utilities Company

Background

Louisville Gas and Electric Company and Kentucky Utilities Company have been offering demand-side management programs to their customers since 1994. Since then, the two companies have worked with an Energy Efficiency Advisory Group (a group of customer/stakeholders, including low-income advocates, formerly called the “DSM Collaborative”) to grow and improve their set of DSM program offerings. In their 2011 DSM filing, the two companies noted that there is “plenty of room for additional cost-effective energy and demand savings,” which is evident given their recent filing for the addition of three new residential energy efficiency programs (LG&E/KU 2011a).

Figure 3. LG&E/KU 2010 Sales



Source: EIA 2011

We were unable to determine how LG&E/KU’s programs have evolved since 1994 because utilities in the Commonwealth are not required to report on program performance ex post and LG&E/KU does not do so voluntarily. However, using LG&E/KU DSM applications as a reference, their portfolios appear to be robust. Data on energy savings do appear sporadically in their DSM applications, though the savings data provided are cumulative (as opposed to new, incremental savings in a given year). Savings data are also reported within the text instead of in tables, and with no accompanying historical data with which make comparisons. Still, given the companies’ experience with DSM and

the magnitude of their costs and savings projections reported in their DSM applications, LG&E/KU seem to be pursuing energy efficiency fairly aggressively.

Program Portfolio

LG&E/KU's program portfolio consists of thirteen demand-side management programs, of which seven focus on delivering energy savings through energy efficiency (the other focus on load management, education programs, etc.). Their residential portfolio includes programs focused on high efficiency lighting, new construction, HVAC tune-ups, low-income weatherization, and home retrofits (audits and rebates for equipment replacement). Their commercial portfolio includes programs focused on HVAC tune-ups and retrofits (audits and rebates for equipment replacement). There are currently no programs (or rates) that are offered to LG&E/KU's industrial customers because of the statutory provision allowing industrial customers to opt out of paying into energy efficiency programs.

In July 2007, LG&E/KU filed their joint application for the review, modification, and continuation of their energy efficiency programs and demand-side management cost recovery mechanisms, upon which the assessment below is based (LG&E/KU 2007). In each DSM plan filing, LG&E/KU reports seven-year projections of the budgets and savings for each program individually as well as for the overall portfolio. The most recent DSM plan was filed in April 2011, which sought approval for the continuation or modification of the thirteen DSM programs mentioned above and three new programs: Smart Energy Profile (home energy reports); Residential Incentives (equipment replacement); and Residential Refrigerator Removal (LG&E/KU 2011a).

LG&E/KU offer cash incentives to customers for three of their existing programs: residential new construction; residential high-efficiency lighting; and commercial retrofits. Incentives for the latter two constitute around 40% of total program costs (42% and 36%, respectively), while incentives for residential new construction are 77% of total program costs. Two of LG&E/KU's new programs will also offer incentives: 60% of the costs of the residential incentives program will be directed towards incentives while 15% of the costs of the refrigerator removal program will be directed towards incentives (customers are given a modest incentive for the removal).

Assessment of Results

The results reported in Table 4 below are from LG&E/KU's joint application for their DSM programs, filed in July of 2007 (LG&E/KU 2007). The filing reports seven-year projections, starting in 2008, of costs and savings for LG&E/KU's program portfolios. For the sake of comparison to other utilities covered in this analysis, we only report LG&E/KU's projections for the 2008-2010 program years. These results do not represent actual program performance in these program years; ex post results for existing programs in LG&E/KU's portfolio were unavailable.

LG&E/KU project minimal annual growth in their DSM programs for the first few years of the 2008-2014 planning period. Incremental annual savings actually decline from 2008-2010 and, although not

reported here, continue to decline through 2014.¹⁰ Still, as a percent of sales, LG&E/KU project savings achievements on par with Duke Energy Kentucky above. However, without DSM status reports that show actual, measured savings from LG&E/KU's programs, it is impossible to determine to what degree the projections varied from actual program performance.

Assuming that LG&E/KU meet the projected savings with expenditures close to the allotted budget, they will be achieving those savings cost-effectively and, for the most part, within the range of CSE values reported above in Tables 1 and 2. Like Duke, LG&E/KU project that the vast majority of their portfolio savings will come from their residential lighting (averaging between 80%-85%) and commercial retrofit programs (see Table A-2 in Appendix A), the latter of which includes lighting along with other equipment (motors, refrigeration, etc.). While lighting retrofits will continue to generate significant savings in the future given new technologies such as light-emitting diodes (LEDs), LG&E/KU's commercial portfolio would benefit greatly from some program additions. Currently LG&E/KU rely more heavily on lighting to drive portfolio savings (as a percent) than any of the other utilities in this assessment. Like Duke, commercial programs targeting new construction, computer efficiency, and systems and controls would drive up portfolio savings considerably.

Table 4. Results for LG&E/KU Energy Efficiency Portfolio

| Program | Program Year | Retail Sales | Savings (of total sales) | Savings* | Costs | Levelized CSE (\$/kWh) |
|---------------------------|--------------|---------------|--------------------------|----------------|-----------------|------------------------|
| | | GWh | % | MWh | Million \$ | 13 yrs |
| Residential | 2008 | 10,590 | 0.66% | 69,892 | \$ 21.17 | \$ 0.03 |
| C&I | | 19,795 | 0.28% | 55,729 | \$ 4.69 | \$ 0.01 |
| Total All Programs | | 30,385 | 0.41% | 125,621 | \$ 25.86 | \$ 0.02 |
| Residential | 2009 | 10,261 | 0.65% | 66,720 | \$ 20.77 | \$ 0.03 |
| C&I | | 18,646 | 0.30% | 56,125 | \$ 4.57 | \$ 0.01 |
| Total All Programs | | 28,907 | 0.42% | 122,845 | \$ 25.34 | \$ 0.02 |
| Residential | 2010 | 11,321 | 0.56% | 63,831 | \$ 21.77 | \$ 0.04 |
| C&I | | 19,992 | 0.28% | 56,519 | \$ 4.73 | \$ 0.01 |
| Total All Programs | | 31,312 | 0.38% | 120,350 | \$ 26.49 | \$ 0.02 |

Sources: LG&E/KU 2007 and 2011a; EIA 2011, 2010a, and 2009

* Savings reported here are projections. It is unclear whether these represent net or gross savings. LG&E/KU reported actual savings in a June 13, 2011 filing in its joint integrated resource plan docket, Case No. 2011-00140. No costs were reported in this filing.

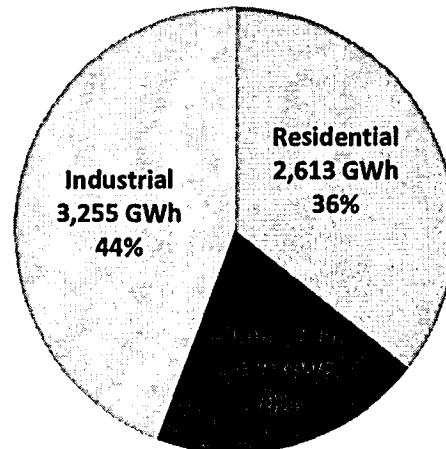
¹⁰ LG&E/KU reported projected savings in their July 2007 filing in terms of cumulative annual, not incremental annual, the latter of which we report in Table 4. Annual sales reported from 2008 through 2010 are taken from the U.S. DOE's Energy Information Administration (EIA 2009, 2010, and 2011), while sales projections after 2010 are taken from LG&E/KU's integrated resource plan filings (LG&E/KU 2011b).

Kentucky Power Company

Background

Kentucky Power Company has offered a variety of demand-side management programs “designed to encourage customers to use electricity efficiently, achieve energy conservation, and reduce the level of future peak demands for electricity since 1994” (KPC 2009). KPC is a subsidiary of American Electric Power and, as such, is subject to its parent company’s strategic plans. In KPC’s 2009 IRP, it notes that the AEP System – East Zone “anticipates significantly expanding the base of demand-side management programs within its footprint,” acknowledging that legislation in Ohio and Michigan requires the implementation of significant programs beginning in 2009, though the level of activity will vary by jurisdiction (KPC 2009). Through 2008, KPC was the only AEP System – East Zone operating company that had “active traditional DSM programs.”

Figure 4. KPC 2010 Sales



Source: EIA 2011

Program Portfolio

Kentucky Power’s program portfolio consists of seven energy efficiency programs and an additional five DSM programs (efficiency and load management) that are administered by an external vendor. The seven programs administered by KPC are all residential – KPC has not directly administered DSM programs for its commercial customers since 2006, citing a steady decline in participation within this customer class leading up to 2006.

KPC’s residential portfolio offers several different types of programs such as: low-income weatherization; HVAC upgrades for mobile homes; improving the efficiency of new mobile homes; home retrofits for electrically-heated homes; high-efficiency heat-pump upgrades; lighting; and energy education for students. The five programs funded by KPC but administered by a third-party vendor include: residential efficient products; commercial HVAC upgrades; residential and commercial HVAC tune-ups; commercial building retrofits; and residential and commercial load management programs. Data on costs and savings for the programs administered by the external vendor were unavailable.

KPC offers incentives to participants of all seven of its residential energy efficiency programs, ranging from 30% to 86% of total program costs. In 2009 and 2010, incentives averaged around 60% of total portfolio costs (60% and 56%, respectively).

Assessment of Results

Although the levelized cost of saved energy for KPC’s residential portfolio falls slightly outside the range of CSEs reported above in Tables 1 & 2, it is still delivering energy savings to its customers cost-effectively when these results are compared to the average retail price of electricity (see Table 5).

Portfolio expenditures have fluctuated since KPC began offering programs (averaging around \$700K), though only in 2009 and 2010 did expenditures increase a significant amount (into the millions of dollars) relative to historical spending (KPC 2011).

While KPC has invested more in its residential DSM portfolio recently, the absence of a robust commercial portfolio limits its ability to achieve energy efficiency savings on par with more successful utilities in the Commonwealth and in other states. As a percent of sales, savings are modest, falling toward the lower end of the range of savings reported above in Tables 1 & 2, though savings have been steady historically. Savings reached a peak and then began to steadily decline in 2000, which was exacerbated by the discontinuation of commercial programs in 2006. Based on data reported in its 2011 DSM application, annual drops in customer participation are the likely culprit in the diminished savings, but whether the factors leading to lower participation were exogenous or endogenous to program design elements (such as marketing and incentives) is difficult to ascertain.

The programs included in KPC's residential portfolio have not changed much since it began offering programs in 1994. With almost 20 years of experience marketing and implementing these programs, it is likely that greater investment (in time and expenditures) would yield even greater savings. The addition of programs that target new construction and whole-house retrofits (beyond low-income customers), for example, would boost residential portfolio savings considerably. KPC could also consider the addition of an autonomous refrigerator recycling program and a home-energy reports / information feedback program, the latter of which would also serve as an educational tool for homeowners. And while industrial energy users are allowed to opt-out of paying for energy efficiency programs through their rates, given that 44% of KPC's sales were to the industrial sector, KPC could potentially generate considerable savings with some well-designed industrial energy efficiency programs.

Table 5. Results for Kentucky Power's Energy Efficiency Portfolio

| Program | Program Year | Partic.* | Retail Sales | Savings (of total sales) | Savings** | Costs | Levelized CSE (kWh) |
|---------------------------|--------------|--------------|--------------|--------------------------|--------------|----------------|---------------------|
| | | | GWh | % | MWh | Million \$ | 13 yrs |
| Residential | 2009 | 6,693 | 2,426 | 0.15% | 3,535 | \$ 1.30 | \$ 0.04 |
| C&I | | - | 4,643 | - | - | \$ - | \$ - |
| Total All Programs | | 6,693 | 7,068 | 0.05% | 3,535 | \$ 1.30 | \$ 0.05 |
| Residential | 2010 | 9,156 | 2,614 | 0.20% | 5,189 | \$ 2.06 | \$ 0.04 |
| C&I | | - | 4,735 | - | - | \$ - | \$ - |
| Total All Programs | | 9,156 | 7,349 | 0.07% | 5,189 | \$ 2.06 | \$ 0.04 |

Sources: KPC 2011, EIA 2011 and 2010a

* Values for the residential lighting program are given in terms of units, not participants. So these values include both number of participating households and number of installed lighting units.

** It is unclear if the savings reported by KPC are net or gross.

Tennessee Valley Authority

Background

Energy efficiency and demand-side management programs have been a part of TVA's energy supply resource mix since the late 1970s. Historically, TVA's programs were focused predominantly on reducing peak demand, though several of their programs also reduced end-use energy consumption. TVA had a substantial array of energy-efficiency programs around the late 1970s and early 1980s, including a major residential, energy efficiency loan program, as well as a variety of commercial programs. These programs were dismantled by the mid-1980s when TVA decided to focus instead on the construction of new power plants. Only recently, in 2007, did TVA adopt a strategic plan that incorporates greater investment in energy efficiency, as part of its goal to lead the Southeast region in increased energy efficiency. Its 2011 Integrated Resource Plan reflects an increased focus on energy efficiency and demand response, with a goal of achieving 3.5% of sales in energy efficiency savings by 2015, which would result in energy savings of around 6,000 GWh by the end of 2015 (TVA 2011).

TVA is a wholesale provider of electricity, so its operational structure is unique. TVA does not serve the majority of its end users directly, so it must work closely with the power distributor community to ensure proper program implementation. In fact, TVA only sells power directly to its industrial customers; residential and commercial customers are served through municipal and cooperative utilities, which purchase power from TVA. TVA is responsible for the designing and developing DSM programs for its direct customers and the customers of its distributors. Distributors then have the option of choosing which of TVA's programs they want to offer to their customers. Distributors also have the option of administering the program with their own resources or soliciting the services of a third-party administrator, Conservation Services Group, which is contracted by TVA to administer its DSM programs.

This unique structure requires its program design process to include not only consumer research, but also requires close involvement by the power distributor community. TVA and distributors coordinate DSM design activities through the Tennessee Valley Public Power Association's (TVPPA) Energy Services Committee. TVA offers programs under the EnergyRight® Solutions brand that includes residential, commercial, industrial, renewable, education/outreach and demand response initiatives (TVA 2011).

Program Portfolio

TVA's program portfolio consists of eight energy efficiency programs, not including demand response/load management programs. The programs in the residential portfolio include: new construction; new manufactured homes; heat pumps; water heaters; in-home energy valuations; and an online auditing tool. TVA's commercial portfolio includes programs focusing on: energy management; HVAC; lighting; and comprehensive building retrofits. TVA also offers two industrial programs: a general retrofit program and a motors/drives upgrade program. In addition, TVA has four (4) pilot programs on its books: a residential consumer electronics program; commercial water

heating upgrades; commercial kitchen retrofits, and; retrofits for data centers (information technology).¹¹

In the data we received, TVA did not disaggregate its energy efficiency program costs by type for its 2010 program year – it only disaggregated them by sector – so we were unable to determine the level of incentives provided to the two customer classes (residential and C&I) as a percent of total program costs. Program costs in 2008 and 2009 were disaggregated by type, between direct and indirect costs, and incentives. Incentives in 2008 constituted almost 50% of total energy efficiency program costs. In 2009, incentive levels dropped, constituting only 17% of total energy efficiency program costs.

Assessment of Results

With the exception of its C&I portfolio in 2009, TVA's program portfolios have performed well (see Table 6). Portfolios have achieved energy savings cost-effectively, relative to the ranges reported in Tables 1 and 2. TVA's C&I programs were still in their nascent stage in 2009, characterized by the low energy savings and relatively high program costs; i.e., TVA was investing money upfront in program design, marketing, etc. before measures were actually being installed in commercial buildings and industrial facilities. This explains the high levelized CSE for TVA's C&I portfolio in 2009. TVA's residential portfolio in 2009, on the other hand, achieved its reported savings cost-effectively, well within the range of CSEs reported in Table 1.

Overall, TVA's portfolio improved in 2010. While savings decreased for the residential portfolio, spending on C&I programs in 2009 clearly generated meaningful results in 2010. The levelized cost of saved energy for the residential, C&I, and overall portfolio falls within the range reported in Table 1.

We were unable to report on the performance of TVA's programs individually because that data was unavailable. TVA is a federally owned utility, so it is not regulated by the KPSC and, therefore, is not required to report its activities to the state. Also, because TVA is a wholesale provider of electricity and does not directly sell power to end-users, with the exception of some of its industrial customers, we have no way of quantifying residential and commercial retail electricity sales because those customers are served through municipal and cooperative utilities. As a result, we were also unable to estimate savings as a percent of sales since no sales data is available for the residential and commercial customer classes.

¹¹ Program data received from TVA did not include program descriptions, so we were unable to determine program design elements that would provide additional detail for these programs.

Table 6. Results for TVA's Energy Efficiency Portfolio

| Program | Program Year | Savings (of total sales) | | Savings* MWh | Costs Million \$ | Levelized CSE (\$/kWh) 13 yrs |
|---------------------------|--------------|--------------------------|---|-----------------|---------------------|----------------------------------|
| | | Retail Sales GWh | % | | | |
| Residential | 2009 | - | - | 8,165 | \$ 0.88 | \$ 0.011 |
| C&I | | - | - | 150 | \$ 0.57 | \$ 0.402 |
| Total All Programs | | - | - | 8,315 | \$ 1.45 | \$ 0.019 |
| Residential | 2010 | - | - | 5,125 | \$ 0.68 | \$ 0.014 |
| C&I | | - | - | 6,131 | \$ 0.77 | \$ 0.013 |
| Total All Programs | | - | - | 11,256 | \$ 1.45 | \$ 0.014 |

Source: TVA 2012

*Savings reported in 2009 were reported as net savings. Savings reported in 2010 were reported as gross savings.

Discussion

In this section we review the overall results from our analysis on utility program performance in the Commonwealth, using the results in Tables 1 & 2 as benchmarks for performance. Following the results, we highlight some important program design and regulatory issues that stakeholders in the Commonwealth should consider in order to raise the performance of utility energy efficiency programs to a level commensurate with leaders in other states.

ASSESSMENT OF OVERALL PORTFOLIO RESULTS

In Table 7 and Figure 2 we present the overall portfolio results for the four Kentucky utilities for the program years 2008-2010. Table 8 reports the same metrics but for utilities from other, comparable states to the Commonwealth (ACEEE 2011), in addition to summary results from Kentucky's utility program portfolios, in order to provide context for evaluating the portfolio results. These tables allow readers to gauge the overall success of the portfolios relative to the performance of utilities in other states.

The low savings percentages and high levelized CSE values are attributable to results from Kentucky Power Company's portfolio, which has not included programs for commercial or industrial customers since 2006. The percent savings take into account savings only from residential programs, which are compared to total sales across all sectors and, therefore, result in the relatively low percent savings. Nonetheless, utility energy efficiency programs in the Commonwealth have generally performed well compared to utilities in other states: results for the metrics in Table 7 fall well within the ranges we report above in Tables 1 and 2 on page 6 above.¹² This is despite the fact that, for decades, electric utilities in Kentucky have maintained some of the lowest electricity prices in the United States.¹³ Energy prices are one important market incentive for utility investment in energy

¹² See Sciortino et. al (2011a and 2011b) for additional reviews of energy savings performance by states and utilities.

¹³ Low energy prices do not guarantee low monthly energy bills for customers. The average residential energy bill in Kentucky (\$107) hovers just below the national average (\$110) (EIA 2011).

efficiency programs, which likely has had some influence on the commitment of utilities in the Commonwealth to pursuing energy efficiency aggressively.¹⁴ Still, more can be done. While the volume of energy savings is fairly modest, savings are being achieved cost-effectively, within the range of CSEs reported in Table 1. In ACEEE's comparison of utility program performance from other states, utilities aggressively pursuing energy efficiency achieved incremental annual savings in the tens-of-thousands to hundreds-of-thousands of megawatt-hours (MWh), achieving close to or above 1% annual savings. These utilities also spent tens-of-millions of dollars to achieve those savings. Still, those savings were achieved cost-effectively.

Kentucky utilities have laid a solid foundation of energy efficiency programs without being statutorily required to do so.^{15,16} However, as ACEEE's assessment of the economic potential for energy efficiency in the Commonwealth attests, a considerable amount of energy efficiency resources remains available in the state for utility programs to capture (ACEEE 2012). Utilities in the Commonwealth have years of experience administering DSM programs, so ramping up existing programs and adding new ones to their portfolios could be done by leveraging existing resources and infrastructure. This expansion would require greater investment on behalf of utilities and consumers alike, but, as other states have shown, it is possible to generate much higher volumes of energy savings while maintaining or improving the cost-effectiveness of energy efficiency programs. With this available potential and the ability of utilities to leverage existing demand-side management infrastructure, utilities in the Commonwealth are in a position to augment their energy efficiency portfolios successfully and for the benefit of all customer classes.

This analysis does not capture any of the industrial sector's voluntary energy efficiency efforts. In Kentucky, the industrial sector is allowed to opt-out of participation in regulated DSM programs. With forty-eight percent of the electricity usage going to the industrial sector, percent-of-sales is a more reasonable metric to use to estimate and report savings if all sectors were participating in regulatory DSM programs.

¹⁴ There are many other market forces that drive investment in energy efficiency programs, such as fuel costs, the age of generation facilities, the ability of existing capacity to meet future demand, , customer demand for energy efficiency services, etc.

¹⁵ Kentucky does not require its utilities to offer DSM programs nor does it require them to file DSM plans. According to KRS 278.285, also known as the "DSM Statute," the Commission only has the authority to "determine the reasonableness of demand-side management plans proposed by any utility under its jurisdiction."

¹⁶ While jurisdictional utilities are not required to offer energy efficiency programs, 807 KAR 5:058 requires utilities to summarize resource acquisitions in their integrated resource plans, including demand-side management programs.

Table 7. Energy Efficiency Program/Portfolio Performance in the Commonwealth, by Utility (2008-2010): Savings, Costs, and Levelized Costs

| Utility and Program Year | Electricity Savings as % | | | Savings (MWh)* | | | Portfolio Costs (Million \$) | | | Levelized CSE (\$/kWh) ¹⁷ | | |
|--------------------------|--------------------------|-------|-------|----------------|--------|---------|------------------------------|---------|---------|--------------------------------------|----------|----------|
| | Res | C&I | Total | Res | C&I | Total | Res | C&I | Total | Res | C&I | Total |
| 2008 | | | | | | | | | | | | |
| Duke | 0.15% | 0.93% | 0.65% | 2,224 | 23,913 | 26,137 | \$ 0.77 | \$ 0.44 | \$ 1.21 | \$ 0.037 | \$ 0.002 | \$ 0.005 |
| KPC | - | - | - | - | - | - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| LG&E/KU | 0.66% | 0.28% | 0.41% | 69,892 | 55,729 | 125,621 | \$21.17 | \$ 4.69 | \$25.86 | \$ 0.032 | \$ 0.009 | \$ 0.022 |
| TVA | - | - | - | - | - | - | \$ - | \$ - | \$ - | \$ - | \$ - | \$ - |
| 2009 | | | | | | | | | | | | |
| Duke | 0.07% | 1.02% | 0.67% | 1,017 | 24,867 | 25,884 | \$ 0.89 | \$ 0.86 | \$ 1.74 | \$ 0.093 | \$ 0.004 | \$ 0.007 |
| KPC | 0.15% | 0.00% | 0.05% | 3,535 | - | 3,535 | \$ 1.30 | \$ - | \$ 1.30 | \$ 0.039 | \$ - | \$ 0.039 |
| LG&E/KU | 0.65% | 0.30% | 0.42% | 66,720 | 56,125 | 122,845 | \$20.77 | \$ 4.57 | \$25.34 | \$ 0.033 | \$ 0.009 | \$ 0.022 |
| TVA | - | - | - | 8,165 | 150 | 8,315 | \$ 0.88 | \$ 0.57 | \$ 1.45 | \$ 0.011 | \$ 0.402 | \$ 0.019 |
| 2010 | | | | | | | | | | | | |
| Duke | 0.30% | 0.55% | 0.46% | 4,723 | 14,155 | 18,877 | \$ 1.00 | \$ 0.72 | \$ 1.72 | \$ 0.023 | \$ 0.005 | \$ 0.010 |
| KPC | 0.20% | 0.00% | 0.07% | 5,189 | - | 5,189 | \$ 2.06 | \$ - | \$ 2.06 | \$ 0.042 | \$ - | \$ 0.042 |
| LG&E/KU | 0.56% | 0.28% | 0.38% | 63,831 | 56,519 | 120,350 | \$21.77 | \$ 4.73 | \$26.49 | \$ 0.036 | \$ 0.009 | \$ 0.023 |
| TVA | - | - | - | 5,125 | 6,131 | 11,256 | \$ 0.68 | \$ 0.77 | \$ 1.45 | \$ 0.014 | \$ 0.013 | \$ 0.014 |

Sources: Duke 2008, 2009, 2010, and 2011; KPC 2011; LG&E/KU 2007 and 2011a

*The savings reported here are not consistently reported as net or gross. For a few utilities, it is unclear what type of savings these values represent.

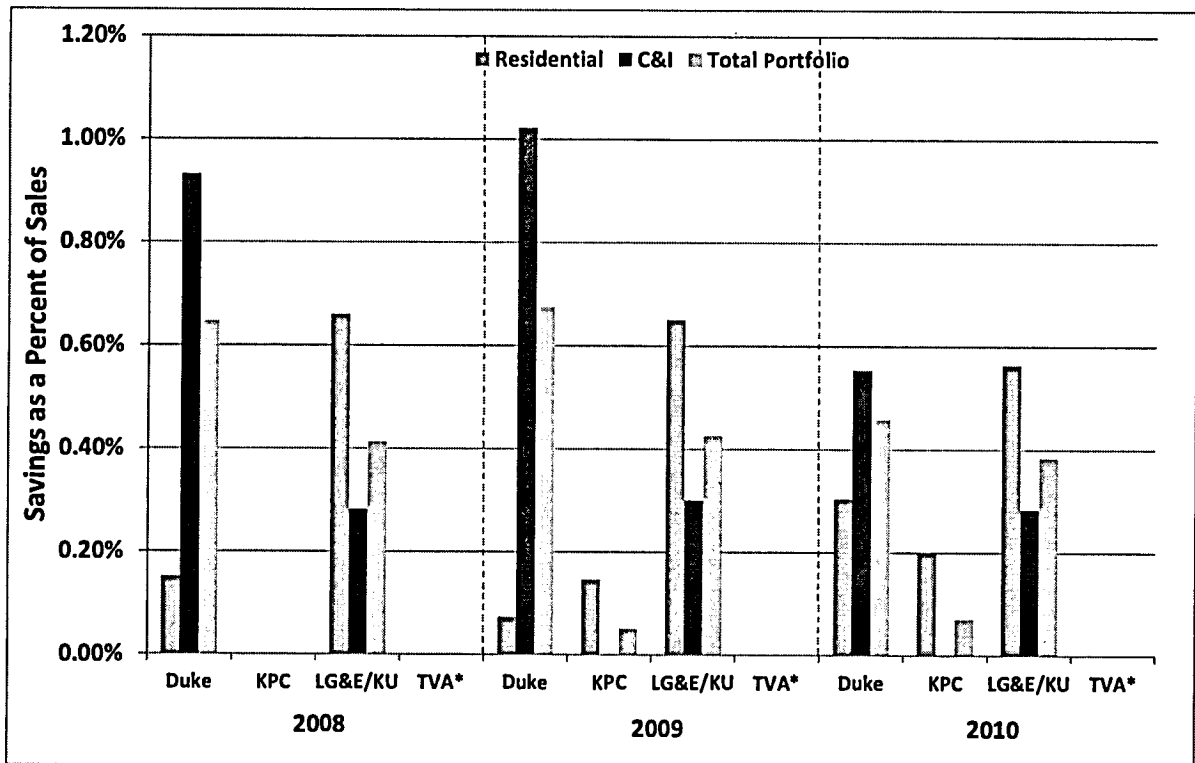
Table 8. Range of Portfolio Results from Non-Kentucky & Kentucky Utility Program Analysis

| Portfolio Results | | | | |
|---------------------------------------|----------------------------|------------------------|------------------------------|-----------------------------|
| Program Year | % Savings (of total sales) | Levelized CSE (\$/kWh) | Average Cost of Saved Energy | Median Cost of Saved Energy |
| Non-Kentucky Portfolio Results | | | | |
| 2009 | 0.04% - 1.06% | \$0.005 - \$0.024 | \$0.015 | \$0.013 |
| 2010 | 0.16% - 1.48% | \$0.006 - \$0.018 | \$0.010 | \$0.009 |
| Kentucky Portfolio Results | | | | |
| 2008 | 0.41% - 0.65% | \$0.005 - \$0.022 | \$0.013 | \$0.013 |
| 2009 | 0.05% - 0.67% | \$0.007 - \$0.039 | \$0.022 | \$0.020 |
| 2010 | 0.07% - 0.46% | \$0.010 - \$0.042 | \$0.022 | \$0.019 |

Source of Non-Kentucky Portfolio Results: ACEEE 2011

¹⁷ CSE values assume a median average measure life of 13 years. These values were calculated by ACEEE using data from utility DSM status reports, when available, and DSM plans.

Figure 2. Electricity Savings as % of Sales, by Sector (2008-2010)



* Retail electricity sales data for TVA's KY operations were unavailable, so we were unable to estimate percentage values for TVA.

INTERPRETING THE RESULTS

The utility program portfolios we have reviewed in this report are disparate among each other as well as utilities outside of the Commonwealth not only with regards to the types and number of programs that are offered, but also with regards to the volume of savings they achieve and the cost of achieving those savings. There are countless reasons why this may be the case, but, generally, the degree to which energy efficiency is pursued is largely influenced by the utility regulatory environment in which utilities operate. A lack of experience administering energy efficiency programs likely does not play a large role in the disparity of portfolio achievements: utilities in the Commonwealth have been offering programs for decades and, thus, are seasoned program administrators. Generally, utilities are unlikely to incur considerable costs pursuing demand-side resources if they are unable to benefit financially from those ventures as they can with investments in supply-side resources.

The primary impetus for significant utility investment in energy efficiency is usually a mandate from the utility regulatory body or the state legislature requiring utilities to meet annual savings targets, usually referred to as an Energy Efficiency Resource Standard (EERS). So it is no coincidence that utility leaders in energy efficiency are those operating in states with aggressive energy efficiency goals (see Sciortino 2011b). The KPSC does not have the statutory authority to set savings targets; however, KRS 278.285 establishes regulatory policies that, in the absence of statutory requirements, provide some motivation for utilities to invest in energy efficiency programs, through “adders” in the DSM surcharge on customer energy bills.

The regulatory motivation for jurisdictional utilities in the Commonwealth to design and implement energy efficiency programs, such as program cost recovery and performance incentives, was codified by Kentucky Revised Statutes (KRS) 278.285 in 1994. Utilities differ in the extent to which they take advantage of these motivational tools, however. Program costs incurred as a result of using these tools are incorporated, or “added,” into the DSM surcharge that appears on the customer energy bill, allowing the utility to recover energy efficiency program costs in addition to some additional financial incentives. The amount of the DSM surcharge is determined by five elements: direct DSM program costs; projected fixed-cost portion of lost sales revenues as a result of the programs; an incentive designed to provide positive financial rewards to a utility to encourage DSM implementation; capital recovery; and a true-up from the previous filing. While these “adders” serve to encourage greater investment in utility energy efficiency programs, ultimately they can also increase the total cost of delivering the programs to the customer.¹⁸

Using portfolio-level data reported by utilities in the Commonwealth to the U.S. Department of Energy’s Energy Information Administration (EIA) through Form 861, it is evident that DSM expenditures have trended upwards for the all three major IOUs since 2001. While overall savings fell around the time of the recession, they have been steadily rising over the last several years. Clearly, then, existing regulatory policy encouraging investment in energy efficiency programs has had some impact on utility investments, though not to the degree that it could have if it was complemented by savings requirements akin to those introduced in other states.¹⁹

KEYS TO SUCCESSFUL PROGRAM PORTFOLIOS

From previous data and program information that we have collected and analyzed in other program assessments, including ACEEE’s assessment of utility programs in other states (ACEEE 2011), we have identified several qualitative trends that are correlated with the success of utility program portfolios:

- ***Experience:*** Utilities that have been engaged with energy efficiency for longer periods of time tend to generate greater savings through their programs. And, as more utilities become involved, the more information we have on “best practices” through which program development can be informed. Of course other factors play an important role in the overall success of portfolios, such as funding and marketing. But ultimately the utilities that best balance these factors will reap the greatest benefit from their programs. Simply investing large

¹⁸ The effect of these adders on the overall cost-effectiveness to the customer is generally modest. The cost-effectiveness of a program is often measured over its life, which requires an avoided cost forecast in order to estimate its net present value of costs and benefits (avoided electricity costs for customers, for example) over that time period. Avoided costs generally increase over time due to a number of factors (such as capacity and infrastructure investments), but the relative effect of DSM program cost recovery on that overall increase is small. DSM surcharges are measured in mills, or 1/1000 of a dollar (per kWh), so any increase in retail prices – and, thus, energy bills – caused by the recovery of program costs will comprise a small percentage of a customer’s total energy bill. Still, while rates may increase in the short-term because less electricity is sold, total customer bills will decline due to savings from efficiency.

¹⁹ It is important to note that DSM program/portfolio performance data stretching back to 2001 is not readily available through the KPSC, so it would be difficult to make this assertion based on publicly-available data in the state. Conversely, the EIA data does not disaggregate portfolio performance data to the program level, rendering it unusable for this program analysis.

sums of money into a program or running massive advertising campaigns will not guarantee success. How that money is spent – the division of funds between program administration, customer incentives, marketing, contractor training, etc. – is more important than the volume of funds invested. And utilities with greater experience tend to know how best to diversify their program investments. Still, the volume of funds invested is crucial, especially since providing customer incentives is a key driver of demand for energy efficiency services (see below).

- **Scope of Portfolios:** The greater the diversity of a program portfolio, the more likely the portfolio will satisfy the demand for services of a heterogeneous market. In other words, programs must reach all customer segments of a market (low- and moderate-income households, small and large commercial buildings, small and large industrial facilities) and target all major end-uses (lighting, HVAC, water heating) in order to maximize savings. In this report, the utility portfolios that we have assessed included at least a few the following programs:
 - **Residential**
 - Lighting (CFLs)
 - Home Energy Assessments (audits) with enhancements (rebates, list of qualified contractors)
 - Appliance Rebates (ENERGY STAR)
 - Appliance Recycling with ENERGY STAR replacements
 - New Home Construction (ENERGY STAR)
 - Low-Income Weatherization
 - **Commercial/Industrial**
 - Lighting
 - New Construction
 - Incentives for High Efficiency HVAC
 - Prescriptive Incentives
 - Custom Incentives (customer works with utilities/contractors to develop custom solutions)
 - Appliance/Equipment Rebates (ENERGY STAR)
- **Marketing:** We did not cover utility program marketing in this report because marketing campaigns are rarely discussed in portfolio status reports. However, understanding the attributes that characterize successful marketing campaigns is important for achieving greater customer participation. Of course, determining the impact of marketing on customer participation is difficult because the correlation between savings from efficiency programs and investment in marketing is not necessarily quantifiable. Nonetheless, here are some key marketing attributes that are widely recognized to augment program marketing campaigns :
 - **Understand Your Market** – Collecting information on market segmentation and demographics is critical for determining how to target programs that will meet the specific needs of customers in a utility service territory. Saturation of efficient products, age of housing/building stock, and customer demographics are examples of market characteristics that are key to understanding these needs.

- **Use Captivating Information** – Marketing materials must capture a customer’s attention. Making the information vivid, concrete, and personal ensures that a customer focuses their attention on the material initially and recalls the information later on in time.
- **Message Framing** – Convincing customers to invest in energy efficiency can be a message delivered either positively (installing energy-efficient light bulbs will save you money) or negatively (if you don’t install energy-efficient light bulbs you will end up spending more money). More often than not, presenting a message that emphasizes losses rather than gains will evoke customers to take action.
- **Emphasize Personal Contact** – The most successful programs are those that develop a regular, personal relationship with the target audience, including post-installation follow-up contacts to verify that measures are working properly and to promote additional measure installation.
- **Incentives:** Providing financial incentives helps catch customer attention and can greatly reduce the upfront cost of measure implementation, depending on the measures being installed. Incentives are clearly a key driver of participation in energy efficiency programs because they lower the upfront costs that must be paid by a customer. Data on the effect of incentive levels on customer participation are limited, so while there is most definitely a correlation between incentive levels and participation, it is hard to determine an exact relationship, if one does exist, especially in light of other relevant factors, such as effectiveness of program marketing and the strength of the local economy.

Demand-Side Management Program Reporting and Data Accessibility

Rigorously documenting the impacts of DSM programs is imperative if utilities, regulatory staff, and other stakeholders are to understand program performance and how programs should be modified in order to perpetuate energy savings and ensure cost-effectiveness. Utility regulatory bodies should strive to require consistency, clarity, and accessibility in the DSM status reports filed by utilities under their purview. By focusing on these criteria and codifying the types of information that must be included in reports, it will be much easier to track program and portfolio performance over time, which will allow analysts and stakeholders to make more informed and justifiable decisions on program design.

Neither the Kentucky Public Service Commission nor the State Legislature has established orders or laws outlining reporting requirements for utility DSM programs, so utilities that report on portfolio performance are doing so of their own volition. The KPSC only has the statutory authority to approve utility DSM plans. As a result, the structure of utility DSM status reports is inconsistent and the content disparate and inaccessible. For example, it is not always clear if program savings are reported as net (of freeriders²⁰) or gross savings. Program costs, if included, are often reported in tables in entirely different sections of a report, which can be troublesome to locate in documents that are often

²⁰ Freeriders are program participants who would have invested in an energy efficient measure even in the absence of utility rebates or incentives for that measure.

over 100 pages in length and include dozens of tables. Costs are also infrequently broken down between types, such as administration, marketing, and incentives, making it difficult to conduct cost/benefit tests from various perspectives (administrator versus participants). Additionally, none of this data is available at the measure or end-use level, making it impossible to evaluate measure performance and ascertain if they should continue to be included in the program.

Arizona is one model that the KPSC can reference when developing its DSM program reporting requirements. Arizona has codified reporting requirements for its utility DSM programs in Title 14 of its administrative code (R14-2-2409). Along with requiring reports to be filed annually on a specific date, R14-2-2409 also lists a dozen individual reporting requirements that must be included in each report. Arizona has also utilized orders issued by the Arizona Corporation Commission (AZCC) to establish additional rules or clarify and modify existing ones, some of which are specific to individual investor-owned utilities and most of which were introduced prior to the establishment of the energy efficiency rules codified in R14-2-2409.²¹ The requirements established through R14-2-2409 and through the AZCC orders allow program data to be found quickly – portfolio summary tables reporting costs and savings are often upfront and bundled together instead of strewn throughout the reports – and the consistency and clarity of the reported data facilitates program analysis over time.

Program data in Arizona are also reported in individual program summaries, allowing data to be easily reconciled. This also gives utilities an opportunity to provide greater detail about the measures or end-uses rebated through each program, such as the relative allocation of program costs and savings, where appropriate.²² Analysts can then evaluate the impact of individual measures or end-uses on overall program savings, which, coupled with data on costs, helps program administrators understand the relative performance of the measures or end-uses and if any design elements need to be modified.

Arizona's experience establishing its existing reporting requirements has not been without difficulty, however. One concern with using both administrative rules and Commission orders to establish requirements is that, over time, they can become hard to track as they increase in number, especially if this is done frequently through Commission orders. This can create needless work on behalf of the utility and Commission staff responsible for compliance. Still, it is hard to identify all reporting needs ahead of time – utility programs and portfolios change regularly and often provide rebates for dozens of individual measures – so it is important for commissions to adjust or introduce new requirements accordingly. But without a central repository for these requirements, compliance can become burdensome. Sorting out how the Commission and utilities will track reporting requirements efficiently over time is crucial.

²¹ A discussion of reporting requirements and previous, relevant AZCC orders can be found in an amended order filed December 29, 2011, Docket # E-01345A-11-0232. See <http://edocket.azcc.gov/>.

²² An energy efficiency program can often provide rebates for dozens of measures, which may require more time than it is worth to report data on each measure individually. Lumping measures into end-uses (HVAC, shell, appliances, lighting) is a practical alternative when the number of qualified measures is large.

Developing reporting requirements is a dynamic process that takes time and careful thought. But without them, the maximum potential of energy efficiency programs will never be realized. Introducing some baseline requirements, such as the energy efficiency rules in Arizona, is a necessary first step. And tracking additional requirements introduced through Commission orders will necessitate rigorous tracking on behalf of Commission compliance staff. But DSM status reports are only as useful as the data they provide and their value cannot be understated, so it is critical for the KPSC to exercise its authority in this area. Any additional costs to utilities of complying are easily justifiable when considering the clarity and accessibility the requirements can create. Fortunately, precedents have been set that will assist Kentucky and ensure detailed documentation of program design and performance.

The Need for Transparency of Demand-Side Management Programs

In a letter written by the Executive Director of the KPSC, Jeff DeRouen, to the Blue Grass Energy Cooperative Corporation in November 2011, it came to light that the Jackson Energy Electric Cooperative was and had been operating DSM programs for which no DSM tariff had been filed (some for over 20 years). In other words, many of the DSM programs were unsupported by a tariff that would set forth the eligibility, charges, payments, and terms and conditions of the programs. Without a tariff there was no formal review by the KPSC, so that it was uncertain that the programs were complying with Commission statutes and regulations. Customers of the cooperatives were being charged and provided incentives for programs that were not reviewed by the KPSC and for which there was no record of the existence of these programs on file at the KPSC.

Since the paramount concern of any state utility commission is to ensure just and reasonable rates for consumers, it is necessary that a commission reviews and files records of all DSM programs operated by utilities under its purview. To address this need, in the letter the KPSC noted that “any program that includes a charge to the customer, provides for any rebate or incentive payment to the customer or a third party, or allows for reduced or discounted rates should be supported by a tariff that sets forth the eligibility, charges, payments, and terms and conditions.” The KPSC noted further that “when the public or the Commission seeks information about the existence of DSM programs, the primary source for that information is the tariffs that each utility has on file [at the Commission].” The KPSC acknowledged the need to address this lack of oversight and laid out a three-step approach that it deemed was “the most practical and equitable approach to take regarding the untariffed DSM programs.” As a result, the KPSC required each jurisdictional electric utility and major gas utility required to file a response by the end of March 2012 stating whether it does or does not currently offer any DSM programs that are not set out in its filed tariffs (KPSC 2011). All jurisdictional utilities have since complied with the filing requirement.

Since DSM programs offered by the Commonwealth’s electric investor-owned utilities are regularly reviewed and approved by the Commission, the redress is directed primarily at the state’s cooperatives, all of which are regulated by the Commission, with the exception of those served by TVA.²³ Sales from cooperatives account for almost 30% of statewide electricity sales, compared to 46%

²³ There are two generation and transmission cooperatives regulated by the KPSC and nineteen distribution cooperatives.

for the investor-owned utilities, which is a significant percentage of the total market share and emphasizes the need to hold cooperatives accountable. Regardless of the extent to which programs were untariffed, consumers in the Commonwealth have a statutory right to know where their money is being directed and, thus, utilities (regulated by the Commission) are statutorily required to participate in a transparent review process that documents utility DSM efforts to ensure that consumers are being treated fairly.

Conclusion

Utilities in the Commonwealth have been funding demand-side management programs for decades despite the absence of a statutory requirement for energy efficiency requiring them to do so. This highlights a few encouraging signs. First, there is a fundamental understanding from utilities that energy efficiency is a low-cost resource that helps meet growing demand for energy, helping to reduce strain on the Commonwealth's energy system and delaying, or even negating, the need for investments in supply-side resources, such as generation facilities and transmission infrastructure. Second, regulatory policy codified in KRS 278.285 and designed to encourage utility investment in energy efficiency appears to be having some impact, though it is difficult to quantify the contribution. Furthermore, recent utility DSM filings exhibit utilities' continuing commitment to energy efficiency: although utilities are ramping up program budgets and savings at low rates, there does not appear to be any danger of utilities rolling back their commitments.

Utility energy efficiency programs in the Commonwealth have generated modest energy savings cost-effectively, which have likely played some role in the Commonwealth's relatively low energy prices. Existing utility program portfolios are robust and target a variety of end-uses, from "low-hanging fruit" such as lighting to deeper retrofits in residential and commercial buildings. These programs provide a solid foundation upon which utilities can build as they carry their portfolios into the future. As administrators contemplate program modifications and additions, there are numerous examples of best-practice energy efficiency programs from utilities in other states that Kentucky's utilities can reference and emulate moving forward.

However, the Commonwealth must prioritize fundamental changes to existing regulatory policy if it is intent on maximizing its energy savings and perpetuating progress well into the future. Kentucky's utilities are not statutorily required to offer DSM programs to their customers, which is not uncommon across the country. But any channeling of ratepayer dollars toward funding energy efficiency programs must initiate a transparent process through which programs are systematically reviewed and filed with the Commission. The issue of DSM programs having been in existence for years and never having undergone a formal tariff process, however, is a matter that was quickly addressed by the Commission and the jurisdictional utilities, with all utilities having filed their tariffs by March 2012.

Documenting DSM portfolio performance through the annual filing of utility DSM status reports is another regulatory issue that requires considerable discussion. Currently there is no statutory requirement for utilities to file reports on the performance of their DSM programs. While utilities are most certainly tracking program performance for their own purposes, the lack of publicly available information on the costs and savings of these programs must be addressed. Although the review of

DSM status reports by the KPSC will require greater resources that may not be readily available, annual filing of portfolio performance is crucial if the Commission and other stakeholders are to understand how programs should be modified to ensure that energy savings are being generated cost-effectively; additionally, there needs to be greater transparency for energy efficiency savings that result from industrial facilities that have opt-out of the utility DSM programs. Consumers also have a right to know how their money is being spent and if it is being spent in a manner that benefits them.

The success of energy efficiency programs in the Commonwealth requires the commitment of all stakeholders, from consumers to program administrators to Commission staff. Utilities have already laid a solid foundation for future growth of their energy efficiency programs, but the state has more work to do in consistently documenting the existence and performance of these programs. And, as found by a previous ACEEE assessment of the cost-effective energy efficiency resource potential available in the Commonwealth, there are considerable savings from energy efficiency yet to be captured by utility energy-efficiency programs (ACEEE 2012). Ultimately, as the process of approving and evaluating energy efficiency programs becomes more efficient and effective, the marginal additional effort and costs could end up saving ratepayers in the Commonwealth considerable sums on their energy bills.

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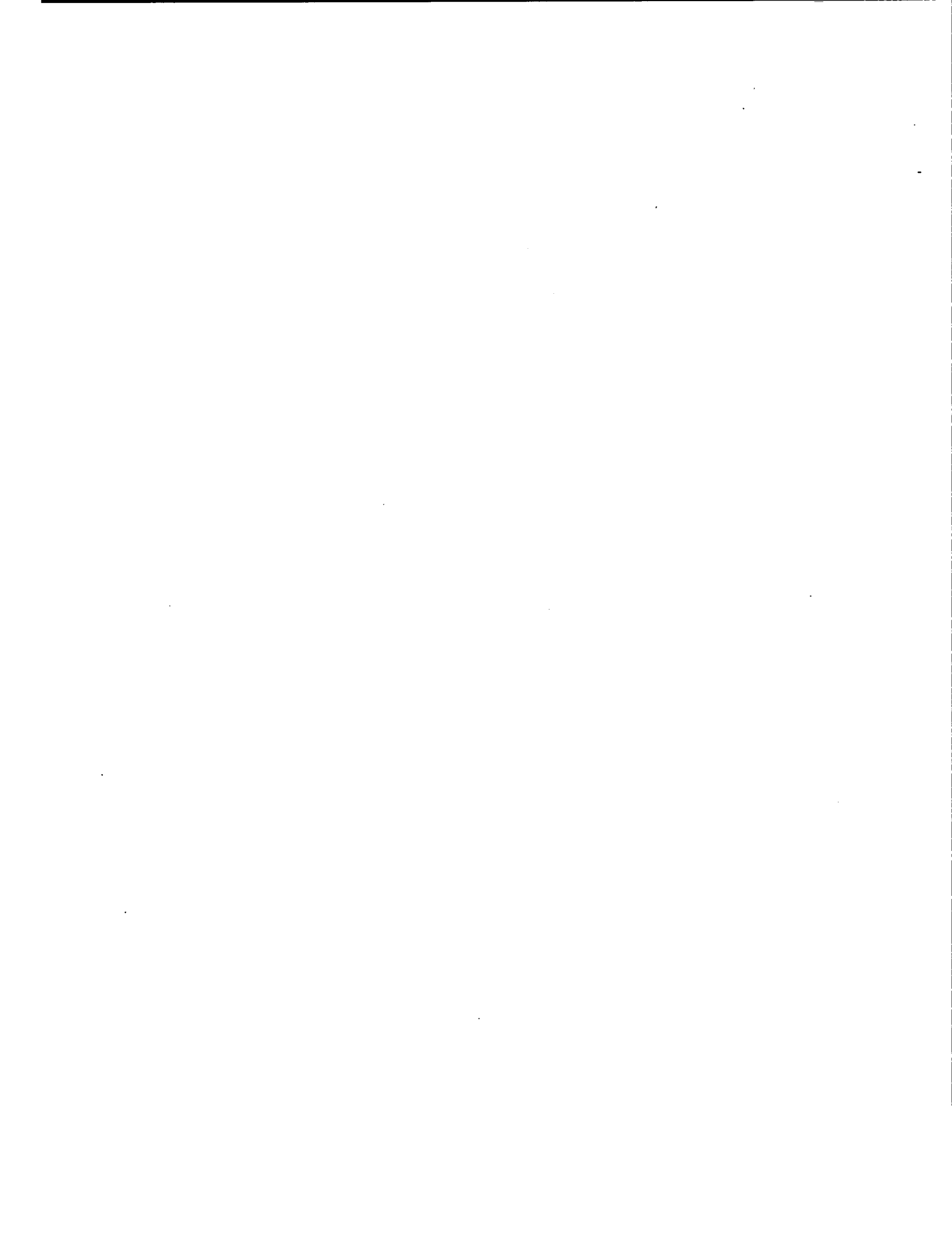
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Appendix A – Full Results of Program Analysis

In this appendix we present the full results of our energy efficiency program analysis. The results are estimated using a range of average measure lifespans between 10-15 years, which is the range of measure lifespans identified in the 2009 ACEEE study, *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs*. This study assumes an average measure lifespan of 10-15 years for electricity programs, with a median of 13 years, which was reported by utilities for their energy efficiency program portfolios in a given program year.

CSE values in these tables are calculated by ACEEE using data reported by utilities. To estimate the levelized cost of saved energy we discount program investments at a rate of seven percent over the life of a measure, or, in the case of programs and portfolios, over the average life of all installed measures in a program. This gives us the present value (cost) of the investments. We then divide by the volume of savings achieved through a particular program, which gives us the cost of achieving each kilowatt-hour of saved energy, in \$/kWh.

Estimates of savings as a percent of sales were made by dividing retail sales, by sector, reported by the Energy Information Administration (EIA 2009, 2010, and 2011) by program/portfolio savings reported by utilities in their DSM status reports and/or DSM plans.

Table A-1. Duke Energy Kentucky Program Portfolio Results

| Program | Program Year | Participation | Retail Sales | % Savings (of total sales) | Net Savings | Costs | Levelized Cost of Saved Energy (\$/kWh) | | |
|-------------------------------|--------------|---------------|--------------|----------------------------|-------------|------------|---|----------|----------|
| | | | GWh | % | MWh | Million \$ | 10 yrs | 13 yrs | 15 yrs |
| Residential | 2008 | | 1,473 | 0.15% | 2,224 | \$ 0.77 | \$ 0.045 | \$ 0.037 | \$ 0.033 |
| Low-Income | | 265 | | | 165 | \$ 0.33 | \$ 0.262 | \$ 0.216 | \$ 0.195 |
| Refrigerator Replacement | | 85 | | | 92 | \$ 0.09 | \$ 0.121 | \$ 0.100 | \$ 0.090 |
| Home Energy House call | | 568 | | | 150 | \$ 0.12 | \$ 0.104 | \$ 0.086 | \$ 0.078 |
| NEED | | 625 | | | 73 | \$ 0.05 | \$ 0.086 | \$ 0.071 | \$ 0.064 |
| ENERGY STAR Products | | 43,123 | | | 1,644 | \$ 0.17 | \$ 0.013 | \$ 0.011 | \$ 0.010 |
| EE Website | | 445 | | | 100 | \$ 0.01 | \$ 0.014 | \$ 0.012 | \$ 0.011 |
| Personalized Energy Report | | | | | - | \$ - | \$ - | \$ - | \$ - |
| C&I | | | 2,569 | 0.93% | 23,913 | \$ 0.44 | \$ 0.002 | \$ 0.002 | \$ 0.002 |
| C&I High Efficiency Incentive | | | | | 23,913 | \$ 0.44 | \$ 0.002 | \$ 0.002 | \$ 0.002 |
| C&I lighting | | 24,777 | | | 16,712 | \$ - | \$ - | \$ - | \$ - |
| C&I HVAC | | 2,683 | | | 7,199 | \$ - | \$ - | \$ - | \$ - |
| C&I Motors | | 4 | | | 2 | \$ - | \$ - | \$ - | \$ - |
| C&I Other | 1 | | | - | \$ - | \$ - | \$ - | \$ - | |
| Custom Incentive – Schools | | | | - | \$ - | \$ - | \$ - | \$ - | |
| Total All Programs | | | 4,041 | 0.65% | 26,137 | \$ 1.21 | \$ 0.006 | \$ 0.005 | \$ 0.004 |
| Residential | 2009 | | 1,404 | 0.07% | 1,017 | \$ 0.89 | \$ 0.113 | \$ 0.093 | \$ 0.084 |
| Low-Income | | 222 | | | 138 | \$ 0.52 | \$ 0.485 | \$ 0.399 | \$ 0.361 |
| Refrigerator Replacement | | 66 | | | 72 | \$ 0.08 | \$ 0.135 | \$ 0.111 | \$ 0.101 |
| Home Energy House call | | 405 | | | 153 | \$ 0.12 | \$ 0.100 | \$ 0.082 | \$ 0.074 |
| NEED | | 390 | | | 45 | \$ 0.08 | \$ 0.230 | \$ 0.189 | \$ 0.171 |
| Energy Star Products | | 10,685 | | | 603 | \$ 0.08 | \$ 0.017 | \$ 0.014 | \$ 0.013 |
| EE Website | | 26 | | | 6 | \$ 0.01 | \$ 0.214 | \$ 0.176 | \$ 0.159 |
| Personalized Energy Report | | | | | - | \$ 0.01 | \$ - | \$ - | \$ - |
| C&I | | 2,434 | 1.02% | 24,867 | \$ 0.86 | \$ 0.004 | \$ 0.004 | \$ 0.003 | |

| Program | Program Year | Participation | Retail Sales | % Savings (of total sales) | Net Savings | Costs | Levelized Cost of Saved Energy (\$/kWh) | | |
|--|--------------|---------------|--------------|----------------------------|-------------|---------|---|----------|----------|
| | | | | | | | | | |
| C&I High Efficiency Incentive | | | | | 24,867 | \$ 0.86 | \$ 0.004 | \$ 0.004 | \$ 0.003 |
| <i>C&I lighting</i> | | 28,580 | | | 16,670 | \$ - | \$ - | \$ - | \$ - |
| <i>C&I HVAC</i> | | 86 | | | 1,931 | \$ - | \$ - | \$ - | \$ - |
| <i>C&I Motors</i> | | 11 | | | 514 | \$ - | \$ - | \$ - | \$ - |
| <i>C&I Other</i> | | 18,410 | | | 4,609 | \$ - | \$ - | \$ - | \$ - |
| Custom Incentive – Schools | | 2 | | | 1,142 | \$ - | \$ - | \$ - | \$ - |
| Total All Programs | | | | 3,838 | 0.67% | 25,884 | \$ 1.74 | \$ 0.009 | \$ 0.007 |
| Residential | 2010 | | 1,555 | 0.30% | 4,723 | \$ 1.00 | \$ 0.028 | \$ 0.023 | \$ 0.020 |
| Low-Income | | 199 | | | 124 | \$ 0.39 | \$ 0.406 | \$ 0.334 | \$ 0.302 |
| Refrigerator Replacement | | 92 | | | 100 | \$ 0.08 | \$ 0.108 | \$ 0.089 | \$ 0.080 |
| Home Energy House call | | 482 | | | 182 | \$ 0.19 | \$ 0.137 | \$ 0.112 | \$ 0.102 |
| NEED | | 488 | | | 57 | \$ 0.08 | \$ 0.177 | \$ 0.146 | \$ 0.132 |
| Energy Star Products | | 28,890 | | | 1,630 | \$ 0.08 | \$ 0.006 | \$ 0.005 | \$ 0.005 |
| EE Website | | 314 | | | 71 | \$ 0.01 | \$ 0.023 | \$ 0.019 | \$ 0.017 |
| Personalized Energy Report | | 7,010 | | | 2,559 | \$ 0.17 | \$ 0.009 | \$ 0.007 | \$ 0.006 |
| C&I | | | 2,562 | 0.55% | 14,155 | \$ 0.72 | \$ 0.007 | \$ 0.005 | \$ 0.005 |
| C&I High Efficiency Incentive | | | | | 14,155 | \$ 0.72 | \$ 0.007 | \$ 0.005 | \$ 0.005 |
| <i>C&I lighting</i> | | 24,801 | | | 336 | \$ 0.45 | \$ 0.174 | \$ 0.143 | \$ 0.130 |
| <i>C&I HVAC</i> | | 89 | | | 69 | \$ 0.06 | \$ 0.109 | \$ 0.089 | \$ 0.081 |
| <i>C&I Motors</i> | | 18 | | | 502 | \$ 0.02 | \$ 0.005 | \$ 0.004 | \$ 0.004 |
| <i>C&I Other</i> | | 4,782 | | | 59 | \$ 0.18 | \$ 0.405 | \$ 0.333 | \$ 0.301 |
| Custom Incentive – Schools | | 25 | | | 13,188 | \$ - | \$ - | \$ - | \$ - |
| Total All Programs | | | 4,117 | 0.46% | 18,877 | \$ 1.72 | \$ 0.012 | \$ 0.010 | \$ 0.009 |
| Residential | 2011 | | | | 2,357 | \$ 1.16 | \$ 0.064 | \$ 0.052 | \$ 0.047 |
| Low-Income | | 234 | | | 146 | \$ 0.64 | \$ 0.569 | \$ 0.467 | \$ 0.423 |
| Refrigerator Replacement | | 76 | | | 83 | \$ 0.07 | \$ 0.114 | \$ 0.094 | \$ 0.085 |
| Home Energy House call | | 511 | | | 201 | \$ 0.14 | \$ 0.091 | \$ 0.074 | \$ 0.067 |
| NEED | | 155 | | | 18 | \$ 0.08 | \$ 0.567 | \$ 0.466 | \$ 0.422 |

| Program | Program Year | Participation | Retail Sales | % Savings (of total sales) | Net Savings | Costs | Levelized Cost of Saved Energy (\$/kWh) | | |
|-------------------------------|--------------|---------------|--------------|----------------------------|--------------|----------------|---|-----------------|-----------------|
| | | | | | | | | | |
| Energy Star Products | | 13,712 | | | 615 | \$ 0.12 | \$ 0.026 | \$ 0.021 | \$ 0.019 |
| EE Website | | 167 | | | 60 | \$ 0.01 | \$ 0.030 | \$ 0.024 | \$ 0.022 |
| Personalized Energy Report | | 3,381 | | | 1,234 | \$ 0.09 | \$ 0.010 | \$ 0.008 | \$ 0.007 |
| C&I | | | | | 5,423 | \$ 0.38 | \$ 0.009 | \$ 0.007 | \$ 0.007 |
| C&I High Efficiency Incentive | | | | | 5,423 | \$ 0.38 | \$ 0.009 | \$ 0.007 | \$ 0.007 |
| <i>C&I lighting</i> | | 19,656 | | | 4,488 | \$ 0.23 | \$ 0.007 | \$ 0.006 | \$ 0.005 |
| <i>C&I HVAC</i> | | 5,738 | | | 606 | \$ 0.11 | \$ 0.024 | \$ 0.020 | \$ 0.018 |
| <i>C&I Motors</i> | | 111 | | | 276 | \$ 0.01 | \$ 0.005 | \$ 0.004 | \$ 0.003 |
| <i>C&I Other</i> | | 32 | | | 53 | \$ 0.02 | \$ 0.047 | \$ 0.039 | \$ 0.035 |
| Custom Incentive – Schools | | | | | - | \$ - | \$ - | \$ - | \$ - |
| Total All Programs | | | | | 7,779 | \$ 1.53 | \$ 0.026 | \$ 0.021 | \$ 0.019 |

Sources: Duke 2008, 2009, 2010, and 2011

Table A-2. LG&E/KU Program Portfolio Results

| Program | Program Year | Retail Sales | % Savings (of total sales) | Net Savings | Costs | Levelized Cost of Saved Energy (\$/kWh) | | | |
|---------------------------|--------------|---------------|----------------------------|---------------|-----------------|---|----------------|----------------|----------------|
| | | GWh | % | MWh | Million \$ | 10 yrs | 13 yrs | 15 yrs | |
| Residential | 2008 | 10,590 | 0.66% | 69,892 | \$ 21.17 | \$ 0.04 | \$ 0.03 | \$ 0.03 | |
| Residential Conservation | | | | 1,495 | \$ 0.64 | \$ 0.06 | \$ 0.05 | \$ 0.04 | |
| Res Demand Conservation | | | | 4,802 | \$ 9.99 | \$ 0.27 | \$ 0.22 | \$ 0.20 | |
| WeCare | | | | 2,297 | \$ 1.73 | \$ 0.10 | \$ 0.08 | \$ 0.07 | |
| Res High Efficiency Ltg | | | | 60,603 | \$ 3.43 | \$ 0.01 | \$ 0.01 | \$ 0.01 | |
| Res NC | | | | 409 | \$ 0.86 | \$ 0.27 | \$ 0.22 | \$ 0.20 | |
| Res HVAC Tune-Up | | | | 286 | \$ 0.20 | \$ 0.09 | \$ 0.08 | \$ 0.07 | |
| C&I | | | 19,795 | 0.28% | 55,729 | \$ 4.69 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| Comm Demand Conservation | | | | 213 | \$ 0.44 | \$ 0.27 | \$ 0.22 | \$ 0.20 | |
| Prescriptive Rebates | | | | 54,988 | \$ 3.18 | \$ 0.01 | \$ 0.01 | \$ 0.01 | |
| Comm HVAC and Tune-Up | | | | 528 | \$ 0.19 | \$ 0.05 | \$ 0.04 | \$ 0.03 | |
| Total All Programs | | | 30,385 | 0.41% | 125,621 | \$ 25.86 | \$ 0.03 | \$ 0.02 | \$ 0.02 |
| Residential | | 2009 | 10,261 | 0.65% | 66,720 | \$ 20.77 | \$ 0.04 | \$ 0.03 | \$ 0.03 |
| Residential Conservation | | | | 1,996 | \$ 0.70 | \$ 0.05 | \$ 0.04 | \$ 0.03 | |
| Res Demand Conservation | | | | 4,803 | \$10.25 | \$ 0.28 | \$ 0.23 | \$ 0.21 | |
| WeCare | | | | 2,296 | \$ 1.74 | \$ 0.10 | \$ 0.08 | \$ 0.07 | |
| Res High Efficiency Ltg | | | | 56,179 | \$ 3.39 | \$ 0.01 | \$ 0.01 | \$ 0.01 | |
| Res NC | | | | 793 | \$ 0.86 | \$ 0.17 | \$ 0.14 | \$ 0.13 | |
| Res HVAC Tune-Up | | | | 653 | \$ 0.34 | \$ 0.22 | \$ 0.18 | \$ 0.16 | |
| C&I | | | 18,646 | 0.30% | 56,125 | \$ 4.57 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| Comm Demand Conservation | | | | 214 | \$ 0.40 | \$ 0.24 | \$ 0.20 | \$ 0.18 | |
| Prescriptive Rebates | | | | 54,988 | \$ 3.15 | \$ 0.01 | \$ 0.01 | \$ 0.01 | |
| Comm HVAC and Tune-Up | | | | 923 | \$ 0.27 | \$ 0.04 | \$ 0.03 | \$ 0.03 | |
| Total All Programs | | | 28,907 | 0.42% | 122,845 | \$ 25.34 | \$ 0.03 | \$ 0.02 | \$ 0.02 |
| Residential | 2010 | 11,321 | 0.56% | 63,831 | \$ 21.77 | \$ 0.04 | \$ 0.04 | \$ 0.03 | |

| Program | Program Year | Retail Sales | % Savings (of total sales) | Net Savings | Costs | Levelized Cost of Saved Energy (\$/kWh) | | |
|---------------------------|--------------|---------------|----------------------------|----------------|-----------------|---|----------------|----------------|
| | | | | | | | | |
| Residential Conservation | | | | 2,247 | \$ 0.74 | \$ 0.04 | \$ 0.04 | \$ 0.03 |
| Res Demand Conservation | | | | 4,802 | \$ 10.79 | \$ 0.29 | \$ 0.24 | \$ 0.22 |
| WeCare | | | | 2,297 | \$ 1.79 | \$ 0.10 | \$ 0.08 | \$ 0.08 |
| Res High Efficiency Ltg | | | | 52,078 | \$ 3.40 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| Res NC | | | | 1,591 | \$ 1.06 | \$ 0.12 | \$ 0.10 | \$ 0.09 |
| Res HVAC Tune-Up | | | | 816 | \$ 0.39 | \$ 0.06 | \$ 0.05 | \$ 0.05 |
| C&I | | 19,992 | 0.28% | 56,519 | \$ 4.73 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| Comm Demand Conservation | | | | 213 | \$ 0.45 | \$ 0.27 | \$ 0.23 | \$ 0.20 |
| Prescriptive Rebates | | | | 54,988 | \$ 3.17 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| Comm HVAC and Tune-Up | | | | 1,318 | \$ 0.33 | \$ 0.03 | \$ 0.03 | \$ 0.02 |
| Total All Programs | | 31,312 | 0.38% | 120,350 | \$ 26.49 | \$ 0.03 | \$ 0.02 | \$ 0.02 |

Sources: LG&E/KU 2007 and 2011a

Table A-3. Kentucky Power Company Program Portfolio Results

| Program | Program Year | Participants | Retail Sales | % Savings (of total sales) | Net Savings | Costs | Levelized Cost of Saved Energy (\$/kWh) | | |
|------------------------------|--------------|--------------|--------------|----------------------------|-------------|------------|---|---------|---------|
| | | | GWh | % | MWh | Million \$ | 10 yrs | 13 yrs | 15 yrs |
| Residential | 2009 | | 2,426 | 0.15% | 3,535 | \$ 1.30 | \$ 0.05 | \$ 0.04 | \$ 0.04 |
| Targeted EE Program | | 342 | | | 581 | \$ 0.55 | \$ 0.12 | \$ 0.10 | \$ 0.09 |
| Mobile Home Heat Pump Prog | | 160 | | | 413 | \$ 0.09 | \$ 0.03 | \$ 0.02 | \$ 0.02 |
| Mobile Home New Cons. Prog | | 208 | | | 350 | \$ 0.11 | \$ 0.04 | \$ 0.03 | \$ 0.03 |
| Modified Energy Fitness Prog | | 801 | | | 522 | \$ 0.31 | \$ 0.08 | \$ 0.06 | \$ 0.06 |
| High Efficiency HP | | 308 | | | 491 | \$ 0.17 | \$ 0.05 | \$ 0.04 | \$ 0.03 |
| Community Outreach CFL | | 3,744 | | | 927 | \$ 0.04 | \$ 0.01 | \$ 0.00 | \$ 0.00 |
| Energy Educ for Students | | 1,130 | | | 251 | \$ 0.02 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| C&I | | | 4,643 | | - | \$ - | \$ - | \$ - | \$ - |
| Total All Programs | | | 7,068 | 0.05% | 3,535 | \$ 1.30 | \$ 0.05 | \$ 0.04 | \$ 0.04 |
| Residential | 2010 | | 2,614 | 0.20% | 5,189 | \$ 2.06 | \$ 0.05 | \$ 0.04 | \$ 0.04 |
| Targeted EE Program | | 400 | | | 726 | \$ 0.90 | \$ 0.16 | \$ 0.13 | \$ 0.12 |
| Mobile Home Heat Pump Prog | | 233 | | | 602 | \$ 0.12 | \$ 0.03 | \$ 0.02 | \$ 0.02 |
| Mobile Home New Cons. Prog | | 204 | | | 343 | \$ 0.13 | \$ 0.05 | \$ 0.04 | \$ 0.04 |
| Modified Energy Fitness Prog | | 1,200 | | | 782 | \$ 0.43 | \$ 0.07 | \$ 0.06 | \$ 0.05 |
| High Efficiency HP | | 761 | | | 1,202 | \$ 0.38 | \$ 0.04 | \$ 0.03 | \$ 0.03 |
| Community Outreach CFL | | 4,811 | | | 1,191 | \$ 0.06 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| Energy Educ for Students | | 1,547 | | | 343 | \$ 0.04 | \$ 0.01 | \$ 0.01 | \$ 0.01 |
| C&I | | | 4,735 | | - | \$ - | \$ - | \$ - | \$ - |
| Total All Programs | | | 7,349 | 0.07% | 5,189 | \$ 2.06 | \$ 0.05 | \$ 0.04 | \$ 0.04 |

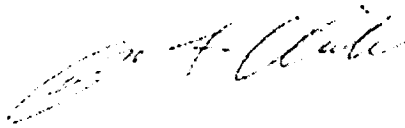
Source: KPC 2011

Request No. 53: Are Mr. Comings or Mr. Loiter aware of any utility that has been able to retain 116 MW of capacity for an investment of \$15 million?

Response No. 53:

The issue in this case is not whether or not another utility has been able to retain 116 MW of capacity for an investment of \$15 million. The issue is whether or not spending \$15 million for the proposed environmental controls represents a wise investment for EKPC and its customers. My testimony and that of Mr. Comings demonstrates that it is not the best investment, as EKPC unreasonably rejected better options. Furthermore, \$15 million does not represent the total investment necessary to retain the 116 MW.

Respectfully submitted,



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Dated: December 18, 2013

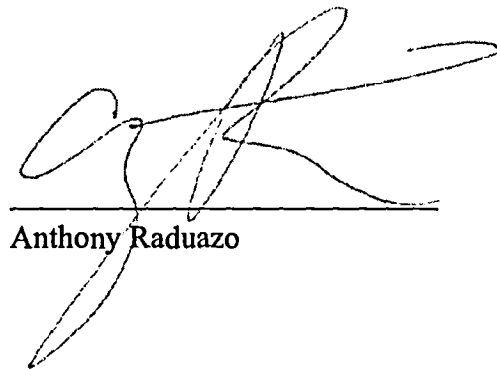
CERTIFICATE OF SERVICE

I certify that I had filed with the Commission and served via U.S. Mail and electronic mail the foregoing Intervenor's Responses to East Kentucky Power Cooperative, Inc.'s Requests for Information on December 18, 2013 to the following:

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