

Commonwealth of Virginia

State Corporation Commission

**Report to the Governor of the Commonwealth of Virginia
and the Virginia General Assembly**



**Report: Study to Determine Achievable and Cost-effective
Demand-side Management Portfolios Administered
by Generating Electric Utilities in the Commonwealth**

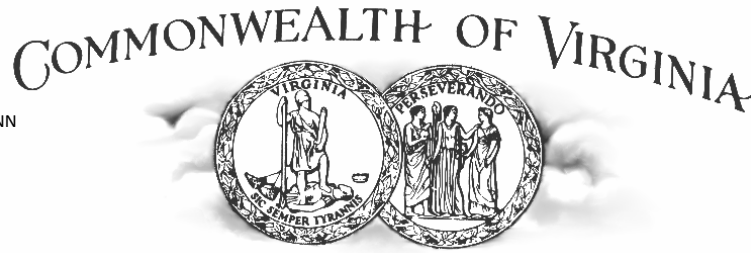
**Pursuant to Chapters 752 and 855 of the
2009 Acts of the Virginia General Assembly**

November 15, 2009

MARK C. CHRISTIE
CHAIRMAN

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

JAMES C. DIMITRI
COMMISSIONER



JOEL H. PECK
CLERK OF THE COMMISSION
P.O. BOX 1197
RICHMOND, VIRGINIA 23218-1197

STATE CORPORATION COMMISSION

November 15, 2009

TO: The Honorable Timothy M. Kaine
Governor, Commonwealth of Virginia

Members of the Virginia General Assembly

The State Corporation Commission is pleased to transmit its report regarding the recent study to determine achievable, cost-effective energy conservation and demand response targets that can be realistically accomplished by the Commonwealth through demand-side management programs administered by each generating electric utility in the Commonwealth, pursuant to Chapters 752 and 855 of the 2009 Acts of the General Assembly. As always, we will gladly provide additional information or assistance upon request.

Respectfully submitted,

Original signed by

Mark C. Christie
Chairman

Original signed by

Judith Williams Jagdmann
Commissioner

Original signed by

James C. Dimitri
Commissioner

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Executive Summary

In accordance with Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly, the State Corporation Commission (“Commission”) conducted an evidentiary proceeding to consider achievable, cost-effective energy conservation and demand response targets that could realistically be accomplished by Virginia’s electric generating facilities. The General Assembly also directed the Commission to make the following determinations: (1) to determine the range of consumption and peak load reductions that are potentially achievable by each electric generating utility; (2) to determine a just and reasonable ratemaking methodology to be employed in the implementation of demand side management programs; and (3) to determine which industry-recognized test should be given the greatest weight when conducting a cost-benefit analysis of demand side management proposals. This Report summarizes the conclusions reached by the Commission following the completion of the statutory mandated evidentiary proceeding.

The Commission did not receive any evidence demonstrating that the existing policy of the Commonwealth regarding a 10% reduction in electric energy consumption through demand side management, demand response and energy efficiency programs is unrealistic or unachievable. We have considered a number of factors in preparing this Report, including the magnitude of recent rate increases borne by ratepayers,¹ and while we acknowledge that additional reductions in electrical energy consumption through demand side management (“DSM”) programs appear to be possible, such reductions could potentially come at additional cost to ratepayers. We also recognize that there are potential offsetting cost savings associated with efficiency programs that result in the

¹See Charts on page 30 of this Report.

reduction of energy consumption and peak load; however, attempting to quantify with specificity such cost savings based on the record before us would be speculative.

Absent any change in the statutory framework that governs Commission proceedings, the Commission will give the greatest weight to the Ratepayer Impact Measure and Total Resource Cost Tests, which are the most consistent with the Commission's current statutory mandates, in evaluating the costs and benefits of specific utility proposals. Consistent with the Commission's existing DSM Rules, the data from the Participant and Utility Cost tests should also be explored to fully evaluate any demand side management proposal.

Due in large part to time constraints and the resulting limited evidence presented in the Commission's proceeding, current economic conditions and rate impact implications, the Commission is not recommending herein any specific mandate to utilities regarding particular targets to be achieved, programs to be required, specific technologies to be used, or narrowly-tailored analyses to be performed. Unless otherwise directed by the General Assembly, the Commission will evaluate proposals on a case-by-case basis, under the applicable statutes, and anticipates that each utility will work toward achieving the Commonwealth's stated consumption reduction goal individually, with programs and technologies tailored to the specific need of the utility and its customers.

Furthermore, while the analysis contained herein is general by necessity given the abbreviated schedule required by the statute, the Commission is open to further analysis should the General Assembly so direct. Such analysis could include the interplay of energy efficiency and demand side management with other Commonwealth policy, such as integrated resource planning or gas decoupling; additional analysis of rate design

methodology and the impact of changes in rate design on energy consumption; assessment of utility bill presentation and any impact on consumption from changes in the amount or quality of information presented to customers; or interim analysis of consumption and peak load reductions, and proposals regarding revision of the ten percent goal previously established by the General Assembly.

I. Introduction and Procedural History

Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly² provided in pertinent part as set forth below:

§ 1. That the State Corporation Commission shall conduct a formal public proceeding that will include an evidentiary hearing for the purpose 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 electric utility in the Commonwealth. As used in this act, "generating electric utility" means a public service corporation that serves electric load at retail, has rates regulated by the State Corporation Commission, and that, as of January 1, 2009, directly owns and operates electric generation facilities in excess of six megawatts, other than diesel generators used for voltage control. The determination of what consumption and peak load reductions can be achieved cost-effectively shall consider standard industry-recognized tests. The Commission shall determine which test should be given greatest weight when preparing a cost-benefit analysis of a demand-side management program, taking into consideration the public interest and the potential impact on economic development in the Commonwealth.

§ 2. That the State Corporation Commission shall report its findings to the Governor and the General Assembly on or before November 15, 2009. Such report shall (i) indicate the range of consumption and peak load reductions that are potentially achievable by each generating electric utility, the range of costs that consumers would pay to achieve those reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 15-year period; and (ii) determine a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-side management programs. This evaluation shall include an examination of the class cost responsibility methods used in other jurisdictions, including, but not limited to, the allocation of costs based on projected class benefits and the allocation of costs based on program participation. The analysis shall also examine other jurisdictions that permit certain nonresidential customers or classes of customers to either be exempt from paying for the utility demand-side management programs or to opt out of participating in or paying for the utility demand-side management programs, and

² Chapter 855 (Senate Bill 1348) and Chapter 752 (House Bill 2531) of the 2009 Acts of Assembly, effective July 1, 2009.

determine if it would be in the public interest for the Commonwealth to have a similar policy.

In accordance with the General Assembly's statutory directive, the Commission issued an Order Establishing Proceeding and Setting Evidentiary Hearing ("Hearing Order") on April 30, 2009.³ Among other things, the Hearing Order scheduled a hearing on September 23, 2009; required publication of notice pertaining to the proceeding in the Virginia Registrar and in newspapers throughout the Commonwealth; directed that Virginia Electric and Power Company ("Dominion" or "DVP"), Appalachian Power Company ("Appalachian Power" or "APCo") and Kentucky Utilities Company d/b/a Old Dominion Power Company ("Old Dominion Power Company" or "KU") be made respondents in the proceeding; required DVP, APCo and KU to file testimony and any briefs on or before June 30, 2009; allowed for notices of participation to be filed on or before June 1, 2009, and for all non-utility respondents to file testimony and/or briefs on or before July 31, 2009; allowed comments to be filed on or before July 31, 2009; and directed the Commission's Staff ("Staff" or "Commission Staff") to file a report (including testimony) and any supporting brief on or before September 9, 2009. In addition, the Commission requested each of the participating utilities, as well as other interested parties, to provide comment on the following questions:

1. What is an achievable, cost-effective energy conservation and demand response target that can be realistically accomplished through the generating electric utility's demand-side management portfolio?
2. What industry-recognized tests should be used in determining cost-effective consumption and peak load reductions and what relative weighting should be

³ See *Commonwealth of Virginia, et rel. State Corporation Commission, 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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly*, Case No. PUE-2009-00023.

- afforded to any test recommended for use by the respondent generating electric utility?
3. How should the Commission define the terms "achievable," "cost-effective," and "be realistically accomplished" as they are used in the statute cited above?
 4. How should the Commission determine the "public interest" in preparing a "cost benefit analysis of a demand-side management program"?
 5. What is the potential impact of the generating electric utility's demand-side management program on economic development in the Commonwealth?
 6. What is "the range of consumption and peak load reductions that are potentially achievable by each generating electric utility"?
 7. What is the "range of costs that consumers would pay to achieve those reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 5 -year period"?
 8. How should the Commission "determine a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-side management programs"?
 9. What "class cost responsibility methods [are] used in other jurisdictions," and "would [it] be in the public interest for the Commonwealth to have a similar policy" to other jurisdictions that permit certain customers to be exempt from participating in and/or paying for a utility's demand-side management programs?

In addition to the three utilities made a part of the proceeding by Commission Order, the Commission received notices of participation from EMeter Corporation, Robert Vanderhye, New

Era Energy, Inc., Meadwestvaco Corporation, Southern Environmental Law Center (with Sierra Club and Appalachian Voices) (“SELC”), Ice Energy Corporation (“Ice Energy”), Virginia Energy Purchasing Governmental Association (“VEPGA”), Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (“the Committees”), Piedmont Environmental Council (“PEC”) and Washington Gas Light Company.

The Commission received written testimony from Dominion, APCo, KU, Staff, SELC, Robert Vanderhye and Ice Energy. Some of the parties filing testimony also submitted legal briefs or other supporting information. Although each party addressed the questions posed by the Commission to varying degrees, in the opinion of the Commission, none addressed all of the questions fully. In addition, the written testimony received by the Commission did not fully address the issues presented by the General Assembly, a problem necessarily exacerbated by the accelerated schedule required in order to produce a report by November 15.

As required by the General Assembly, the Commission held an evidentiary hearing. The hearing was convened in Richmond on September 23 and 24, 2009. At the evidentiary hearing, the witnesses sponsoring the prefiled testimony of Dominion, APCo, KU, Staff, SELC and Robert Vanderhye appeared and were subject to cross-examination by the parties. Although Ice Energy submitted written testimony, it did not appear at the hearing.

Given the time frame for this matter, the Commission spent approximately six months receiving and reviewing testimony, conducting the evidentiary hearing and considering the evidence presented during the course of the proceeding. This is a substantially and materially shorter period than has been allotted in most states considering such topics, necessitating the Commission’s consideration of this matter at a general level. Should the General Assembly

deem additional, more detailed analysis to be appropriate, the Commission will conduct any such proceeding as requested.

The Commission further notes that the analysis contained herein does not stand in isolation and must be evaluated in conjunction with other statutory mandates and regulatory proceedings. For example, § 56-599 of the Code of Virginia requires each electric utility to file with the Commission an Integrated Resource Plan ("IRP") that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility. The IRPs, therefore, take into consideration load reductions forecast to be achieved via energy efficiency, and include the sort of demand side resources at issue in the instant analysis. Allegheny Power,⁴ Dominion Virginia Power and Appalachian Power filed their initial IRPs in September 2009, and the Commission received public comment on the proposals through November 13, 2009.⁵ KU filed its IRP on July 1, 2009.⁶

In addition, § 56-585.1 A 5 c permits utilities to petition the Commission for approval of a rate adjustment clause to recover projected and actual costs for the utility to design, implement, and operate energy efficiency programs, including a margin to be recovered on operating expenses. Dominion filed such a request with the Commission earlier this year, seeking recovery of costs associated with twelve proposed demand-side programs. Dominion's proposal is under consideration by the Commission in Case No. PUE-2009-00081. Although some of the parties in the instant proceeding discussed Dominion's proposals in general terms, the Commission

⁴ Because Allegheny Power does not directly own and operate electric generation facilities, it was not made a party to Case No. PUE-2009-00023.

⁵ Allegheny Power's plan has been assigned case number PUE-2009-00095. Dominion Virginia Power's plan has been assigned case number PUE-2009-00096. Appalachian Power's plan has been assigned case number PUE-2009-00097.

⁶ KU's IRP has been assigned Case No. PUE-2009-00062.

makes no determination regarding such programs or the recovery of such costs herein. The specifics of the utility IRPs and Dominion's application under § 56-585.1 will be considered in the applicable proceedings, and nothing herein is intended to predetermine any of the issues in those proceedings.

A number of other proceedings involving DSM and other environmental issues have recently been addressed by, or are currently before the Commission.⁷ Likewise, each of these cases has been addressed or will be addressed on a case-by-case basis applying applicable statutory standards and nothing herein represents a predetermination of any issue in these proceedings.

II. Definitions

As used in this Report, the following terms shall be defined as set forth below:

Demand Response (also referred to in this Report as "DR"). Measures or programs intended to reduce electric demand at the time of peak load on the entire electric system or some defined sub part of the electric system. This is accomplished by curtailing electrical use at peak times and possibly shifting that usage to off-peak periods.

⁷ See *Ex Parte: In the matter of establishing interconnection standards for distributed electric generation*, Case No. PUE-2008-00004; *Ex Parte: In the matter of amending regulations governing net energy metering*, Case No. PUE-2008-00008; *Ex Parte: In the matter of amending regulations governing net energy metering*, Case No. PUE-2009-00105; *Ex Parte: In the matter of establishing rules of the State Corporation Commission governing exemptions for Large General Service Customers under § 56-585.1 A 5 c of the Code of Virginia*, Case No. PUE-2009-00071; *Appalachian Power Company*, Case No. PUE-2009-00068 (Application for Approval of Retail Demand Response Programs); *Appalachian Power Company*, Case No. PUE-2008-00003 (Application For approval to Participate in the Virginia Renewable Energy Portfolio Standard Program); *Appalachian Power Company*, Case No. PUE-2008-00057 (Application For approval of Renewable Power Rider); *Appalachian Power Company*, Case No. PUE-2009-00102 (Application For approval of purchase power agreements as part of its participation in the Virginia energy portfolio standard program); *Virginia Electric and Power Company d/b/a Dominion Virginia Power*, Case No. PUE-2008-00044 (Application For approval of Renewable Energy Tariff); *Virginia Electric and Power Company*, Case No. PUE-2009-00082 (Application For Approval to Participate in a Renewable Energy Portfolio Standard program); *Ex Parte: In the matter of establishing rules of the State Corporation Commission governing rates for stand-by service furnished to certain renewable cogeneration facilities*, Case No. PUE-2009-00080; *Ex Parte: Establishing pilot programs to develop certain rate structures for renewable generation facilities*, Case No. PUE-2009-00084.

Demand-Side Management (also referred to in this Report as “DSM”). Measures or programs that deliver either Energy Efficiency (“EE”) or Demand Response (“DR”) as defined above.

Energy Conservation. Actions that change end-use customer demand characteristics so as to reduce the amount of end-use energy required. This may be accomplished by improving energy efficiency (“EE”) or by simply discouraging the use of energy.

Energy Efficiency (also referred to in this Report as “EE”). A type of energy conservation that seeks to deliver an end-use service in a manner that requires the consumption of less electric energy while providing an equivalent level of end-use energy service.

Categories of “Potentials”:

Achievable Potential. That part of economic potential that can be achieved by taking into account the various barriers to the adoption of the energy efficient or demand reduction measures. Even if utility programs could be funded to a level that would perfectly inform customers about energy efficient choices and give them an incentive large enough to put energy efficient measures on an economic par with the baseline, some customers would still refuse to adopt such measures. Customers’ reasons for not doing so might include cost, aesthetics, functionality, or a reluctance to be inconvenienced.

Economic Potential. The amount of energy and peak demand reductions that would result if all homes and businesses were to adopt the most efficient, commercially available cost-effective technologies and measures. That is, the portion of the technical potential that would pass a cost effectiveness screen that compares the present value of the bill savings that result from the adoption of the energy efficient measures’ over its useful life to a given baseline. Because no incentives are considered, an implicit assumption is that customers will maintain energy efficient measures until those measures reach the end of their useful lives.

Maximum Achievable Potential. The part of economic potential that can be achieved by taking elemental customer barriers into account (see definition of Achievable Potential), without consideration of other existing market, financial, political, and regulatory barriers, including the impossibility of providing all customers with perfect information about their efficient choices and the fact that utilities never have unlimited budgets for DSM programs.

Technical Potential. The amount of energy and peak demand reductions that would result if all homes and businesses were to adopt the most efficient, commercially available technologies and measures regardless of cost. Cost effectiveness and market acceptance considerations are not included.

Cost-Benefit Tests:

Participant Test. The purpose of the Participant Test is to estimate the costs and benefits for those customers who choose to participate in a given conservation or energy efficiency program, and thus, is a measure of the attractiveness of a given program to potential participants. It does not, however, capture the complexities and diversity of customer decision-making. The benefits in the calculation of the test are the reductions in participating customer's bills, any incentive paid by utilities or third parties, and any federal, state, or local tax credit received. The costs are any out-of-pocket expenses incurred by participants and any bill increases that participants incur.

Program Administrator Test (also known and referred to in this Report as the "Utility Cost Test"). This test measures the net costs of a conservation or energy efficiency program as a resource option to the program administrator or the utility. For a given utility, the Program Administrator Test indicates the difference between a utility's avoided costs and the utility's costs to implement the program. The test does not include participants' costs, and thereby, reflects only a portion of the full costs of a program. The benefits considered are the avoided costs of energy and demand. The costs are the program or implementation costs for the utility, the incentives paid to participants, and any increased supply costs that may result from the program.

Ratepayer Impact Measure Test. The Ratepayer Impact Measure Test (also referred to in this Report as the "RIM Test") provides an indication of any change in rate levels as a result of a program. In other words, it is an indication of the impact of a program on customer bills or rates due to changes in utility revenues and operating costs caused by the program. As its alternative name, the Non-Participant Test, indicates, the test provides a measure of the impact of a conservation or energy efficiency program on customers who do not participate. The benefits considered in this test are the avoided supply costs related to transmission, distribution, capacity, and generation (if applicable). The avoided supply costs are measured as a reduction in total costs or revenue requirements as a result of the program. Any revenue gain resulting from a conservation or energy efficiency program is also considered a benefit. The costs used in this test are the program costs incurred by the utility and/or other entities incurring costs for creating or administering the program, the incentives paid by the utility, and any revenue loss associated with a program. Any increased supply cost resulting from a program's implementation is also considered a cost.

Societal Test. The Societal Test is structurally similar to the Total Resource Cost Test; however, it goes further in that it attempts to quantify the change in total resource costs to society as a whole rather than to only the service territory of a given utility. The California Standard Practice Manual states that the Societal Test differs from the Total Resource Cost Test in at least one of five ways. Brevity leads this testimony to mention only the inclusion of external costs such as environmental or other social costs, broader measures of marginal cost, and the use of a societal discount rate as substantial differences between the two tests. The test results may be expressed in several ways. Two of the most common methods of expression are as a net present value and as a ratio. If a test result is expressed as a ratio, the total benefits are divided by the total costs. A ratio greater than one indicates that the benefits exceed the costs.

Total Resource Cost Test. The Total Resource Cost Test (also referred to in this Report as the “TRC Test”) is an indicator of net cost of a conservation and energy efficiency program based on the total costs including the participants’ and the utility’s costs. It has sometimes been called the All Ratepayers Test. It may be considered an indicator of the change in the average cost of energy services across all customers. In another sense, it may be considered as the summation of the benefit and cost terms in the Participant Test and the RIM Test. In this latter respect, the test ignores the issue of cross-subsidies between program participants and non-participants. The benefits used to calculate this test are the avoided supply costs and any applicable federal, state, and/or local tax credits. The costs in the test calculation are the utility’s program costs, the net participant costs, and any increased utility supply costs.

III. Position of the Parties

As discussed above, the Commission received testimony and supporting documentation from the three identified utilities, as well as Commission Staff and other interested parties. The Commission also received written and electronic public comments, and oral testimony, from interested persons not formally participating as respondents in the proceeding. Filed testimony is being submitted as a separate Appendix to this Report, and other documentation submitted in this case is available on the Commission’s website at <http://scc.virginia.gov/case>.⁸

⁸ The Commission received written public comments from the following: Richard A. Reed, the Audubon Society of Northern Virginia, the Virginia Electric Cooperatives, John A. Murphy, Brian P. Toll, Tunstall C. Powers and the Virginia Manufacturers Association.

A. Virginia Electric and Power Company

Dominion recommends using DVP's 15-year load forecast (which the company has also used in its IRP) when setting DVP's DSM/Energy Efficiency target. DVP explains that there is no "agreed upon" target by regulators, utilities, environmentalists and customers, but notes that various studies have been performed regarding DSM and energy efficiency, including a recent study performed by the Electric Power Research Institute (the "EPRI Study") and a recent report prepared by the American Council for an Energy-Efficient Economy (the "ACEEE Report"). DVP believes the range of possible consumption savings from 2010 to 2030 set forth in the EPRI Study (8% to 11%) based upon 2008 as a base year is reasonable. In contrast, DVP believes the ACEEE Report's findings are overly ambitious with regard to achievable DSM levels.

In DVP's opinion, a 10% DSM/Energy Efficiency target is "realistically accomplishable" for DVP over 15 years, based upon 2006 as the company's base year. DVP also advocates the use of interim targets to assess "achievability" and "cost-effectiveness" related to meeting long-term targets and suggests that companies be required to report periodically the results of programs, including their actual costs and customer acceptance and assessment for DSM programs. DVP states that although a particular DSM portfolio or program may be cost-effective over the long term, the initial costs associated with the portfolio or program may make it "impractical" to implement.

With respect to the General Assembly's directive that the Commission determine which industry test should be given the greatest weight when evaluating the cost-effectiveness of DSM programs, DVP advocates the Commission's continued consideration of all four tests set forth in the Commission's DSM Rules—that is, (1) the Ratepayer Impact Measure test, (2) the Total Resource Cost test, (3) the Participant test, and (4) the Utility Cost test. Furthermore, rather

than applying these tests to individual DSM programs, DVP recommends that the tests be applied to entire DSM portfolios.

DVP explains that industry consideration of whether particular DSM and efficiency targets are “achievable” generally involves the evaluation of three categories of “potential” (such categories being recognized in the EPRI Study)—(1) technical potential (that is, potential savings achieved using the most efficient commercially available technologies and measures regardless of cost), (2) economic potential (that is, potential savings achieved using the most efficient, commercially available cost-effective measures), and (3) achievable potential (that is, potential savings taking into account realistic barriers to customer participation).

DVP argues that achievable DSM could free-up capacity on peak days “that will allow for additional economic growth and increased reliability” in the Commonwealth. However, it cautions that if DSM targets are too aggressive and investments in new generation are not made in a timely manner, then economic development can be hampered because there could be a shortfall of available, reliable and affordable electricity.

Finally, DVP believes that program costs should be assigned to the “participating jurisdiction,” as “[i]t would be unfair to allocate costs of these programs across the system because certain jurisdictions are not eligible to participate in the programs and should not bear cost responsibility because of the participation of another jurisdiction’s customers.” DVP also notes that the General Assembly has now passed legislation allowing large general service customers to opt-out of DSM programs and providing that large customers shall not be required to pay for the costs of DSM programs. Under the circumstances, DVP believes that Commission’s consideration of the methods used in other states with respect to industrial customer opt-outs and exemptions has become somewhat irrelevant.

B. Appalachian Power Company

APCo submitted comments, the pre-filed testimony of three witnesses, a 2009-2013 DSM Action Plan (“APCo DSM Plan”), and DSM Potential Study (the “Summit Blue Study”) for the Commission’s consideration.⁹ In its comments, APCo, similar to DVP, advocates that any “targets be short-term to account for rapidly evolving technology, as well as to account for economic uncertainties.” APCo also recommends periodic assessment and, if necessary, “periodic recalibration” of DSM goals “to align a utility’s efforts with prevailing conditions.”

When considering the “public interest” and in the process of picking a test to evaluate the cost-effectiveness of DSM programs, APCo urges the Commission to consider whether such programs will result in just and reasonable rates while not interfering with a utilities ability to provide reliable service. APCo also argues that the Commission does not have jurisdiction to consider environmental factors (or other societal externalities) when adopting a test. Instead, APCo urges the Commission to adopt the TRC test when evaluating the cost-effectiveness of DSM plans.

APCo believes only “DSM programs that are reasonably predicted to be cost-effective in terms of their overall impact on costs, as compared to the cost of traditional supply options” should be considered for implementation. APCo strongly recommends against setting specific targets for utilities until after the “fundamental regulatory underpinnings of DSM implementation and analysis” have been established.

According to APCo, the Summit Blue Study assesses the relative potential of various DSM programs to produce various energy or peak demand reductions in Virginia and concludes that a range of outcomes are possible with respect to reduced energy and demand savings.

⁹ Due to their length, the APCo DSM Plan and Summit Blue Study are not included in the Appendix to this Report. However, they are available for review on the Commission’s website at <http://scc.virginia.gov/case>.

However, APCo advocates a more moderate DSM program than that supported by its Summit Blue Study—that is, an initial 5-year program period achieving a 2% savings from APCo’s 2008 energy consumption and 5% of its peak load, at a cost of from \$80 to \$100 million. This could result in a significant rate increase for customers affected.

APCo notes that the automatic exemption for large customers applies to approximately 20% of APCo’s largest customers – representing approximately 14% of APCo’s total retail consumption and 10% of APCo’s annual revenue. APCo notes further that additional large customers will be permitted to opt-out of DSM programs, subject to regulations that are currently being considered by the Commission. This potential exemption would apply to 22% of APCo’s Virginia retail consumption and 17% of its annual revenue.¹⁰

According to APCo, the Summit Blue Study estimates potential levels for energy efficiency and demand response over a 20 year period—based on Base, Low and High Cases for achievable potential. Summit Blue then used the results of its study to create the APCo DSM Plan—a sample 5-year plan based upon APCo’s “Base Case of achievable potential” and including additional information pertaining to potential programs, necessary staffing levels and costs.

APCo cautions that there are a number of uncertainties and limitations associated with the Summit Blue Study and the APCo DSM Plan. For example, the results of the Summit Blue Study are based upon historic economic conditions and that future economic uncertainties could negatively affect customers' willingness to participate. In addition, customer opt-outs could impact the results of the Summit Blue Study.

¹⁰ To the extent that large customers opt-out of such DSM programs, the Commission notes that the utility's remaining customers will be responsible for bearing the burden of the costs.

APCo supports the Summit Blue Study's recommendation for a multi-year program portfolio approach to DSM implementation, and indicates that it may not be possible to effectively analyze the cost of a program on a short time basis because there are likely to be significant, one-time upfront investment costs associated with "ramp[ing] up" a program.

It is APCo's opinion that the company can realistically implement energy efficiency and demand response programs achieving savings equivalent to approximately 2% of the energy consumed in 2008 and 5% of 2008 peak demand within 5 years of program implementation. It explains that these levels are consistent with the "Low Case" results discussed in the Summit Blue Study. However, Virginia's statutory opt-out provisions may affect reductions. In addition, like Dominion, APCo advocates the use of actual 2008 peak demand and energy consumption levels, rather than forecasted values, because of uncertainties with respect to changes in forecasted load.

In quantifying the benefits to customers associated with demand response and efficiency measures, the Summit Blue Study takes into account the avoided cost of energy and the avoided cost of capacity.

C. Kentucky Utilities Company d/b/a Old Dominion Power Company

Although KU has not implemented demand response or energy efficiency programs in its Virginia territory, KU provided data relative to its programs in Kentucky. KU will achieve a 1.2% energy savings (from 2008 to 2014) at an approximate annual cost of \$26 million. It subsequently indicated, however, that it "is not possible to know with certainty whether similar results (scaled for KU/ODP's smaller customer base) are achievable in Virginia."

KU believes the Participant Test, the RIM test, the TRC test and the Utility Cost test should all be considered. However, KU has "historically placed additional weight" on the TRC

test because “it is the most comprehensive indicator of whether a potential DSM/EE program will create net benefits for customers and utilities.

KU could achieve a DSM/EE goal of 5% of its forecasted energy throughput in 2024 in Virginia at a cost of \$19.3 million, with an estimated rate impact of \$0.030 per kWh for residential customers and \$0.009 per kWh for commercial customers (these impacts include program costs, lost revenues and marginal incentives). KU projects that meeting a goal of 20% would cost \$77 million, with an estimated rate impact of approximately \$0.122 per kWh for residential customers and \$0.037 per kWh for commercial customers.

With respect to ratemaking, KU believes it is appropriate for each customer class to bear the cost of DSM/Efficiency programs that are available to the class. KU also opines that the ability of large industrials to opt-out of DSM programs is not in the public interest.

Finally, KU argues that the Commission should not recommend a specific DSM/Efficiency target for KU in its report to the General Assembly.

D. Southern Environmental Law Center

SELC claims that efficiency alone can achieve energy savings of 12% “of forecast load in 2022” and can also result in a peak demand reduction of more than 3,900 MW. SELC believes demand response can provide for additional peak reductions of almost 1,700 MW. SELC concluded that Virginia can achieve energy savings of 1.3% of load each year within 4 years of program implementation. To acquire these savings, SELC estimates a cost of between \$3 to \$4.5 billion – but maintains that spending this amount on efficiency measures will avoid the necessity of spending even more money on traditional energy supply.

According to SELC, customers do not need to change their behavior to reach such savings but, instead, the savings can be reached through changes in lighting, equipment and

building practices. It suggests that utility-sponsored efficiency programs can eliminate investment barriers to achieving such results. SELC also expresses a preference for short-term targets as a “prudent policy approach” but opines that the setting of long-term goals indicates a commitment to sustained energy efficiency efforts.

SELC believes Virginia should be able to reach comparable results to other jurisdictions establishing more aggressive targets than Virginia’s existing policy. SELC states that Virginia’s climate does not impose constraints on DSM/efficiency development and SELC notes that Virginia’s historically low retail electric rates have provided less of an incentive for efficiency. The avoided costs of new supply, transmission and distribution in Virginia “will not significantly limit efficiency potential.”

SELC argues that the recent ACEEE Report prepared for Virginia “presents a reasonable macro-level assessment of the potential for energy efficiency and demand response to reduce the need for centrally-generated electric supply to meet the needs of Virginia’s consumers.”

SELC believes that application of the TRC test of cost-effectiveness, the test preferred by the SELC, to the savings potentials outlined in the ACEEE Report would result in a determination of cost-effectiveness because, in its opinion, retail rates are likely to be lower than Virginia avoided costs.

SELC says that the ability of larger customers to opt-out of DSM/efficiency programs does not cause it to change its conclusion, “materially,” that Virginia can achieve energy savings of 1.3% of load each year within 4 years of program initiation. SELC believes that “annual savings of 1.3% of customer load that *participates* can still be realistically accomplished” regardless of opt-out provisions.

SELC relies upon the National Action Plan for Energy Efficiency, which was cited in the Virginia Energy Plan, as the basis for its figures. By their definition, cost-effective energy investments “will cost Virginia rate-payers less than alternative supply-side resources.” While energy efficiency programs may sometimes raise rates, “primarily because they result in the utility’s fixed costs being spread over a smaller number of kWh,” most customers will have the ability to reduce their energy bills “despite small increases in rates.” Thus, SELC believes that the RIM test is an inappropriate measure of DSM/efficiency cost-effectiveness “because it ignores the large benefits to ratepayers as a group from these efforts.”

SELC further testified that the various industry tests of cost-effectiveness should not be balanced or applied together. Instead, SELC advocates the exclusive use of the TRC test – with certain adjustments. When considering potential for DSM that is “achievable” and can be “realistically accomplished” in Virginia, SELC advocates consideration of the “maximum” potential energy savings that can be achieved in the Commonwealth consistent with definitions set forth in the National Action Plan for Energy Efficiency and as augmented by “best practice” guidelines for integrated resource planning. Similarly, SELC recommends setting utility DSM targets equal to the maximum achievable potential available.

When comparing generation to DSM alternatives, SELC maintains that DSM is “‘hands down’ the cheapest way to provide for Virginia’s energy needs right now and for the foreseeable future.”

With respect to ratemaking methodology, SELC opines that DSM program costs should be allocated among all rate classes because DSM measures result in an overall reduced need for capacity. SELC also recommends allocating the costs of conservation programs using an “energy” allocation factor and allocating the costs of capacity reduction programs using a

“capacity” allocation factor. For programs producing a combination of energy and capacity savings, SELC advocates using an annual supply cost allocation factor. SELC does not believe allowing certain customers to be automatically exempt from paying DSM program costs to be in the public interest.

Finally, SELC maintains that energy efficiency programs in Virginia can supply 12% of Virginia’s needed electric power by 2022. SELC further maintains that efficiency opportunities are abundant, readily available, reliable and affordable in Virginia. With respect to affordability, SELC estimates the cost of efficiency programs at around 3 cents per kWh as compared to a cost of 9.3 cents per kWh associated with the construction of DVP’s Wise County coal plant.

SELC also emphasizes that demand response and energy efficiency efforts are different and that the potential for savings associated with efficiency are greater than those associated with demand response. In addition, SELC maintains that the expected federal regulation of greenhouse gases makes energy efficiency efforts even more important.

E. Robert Vanderhye

Mr. Vanderhye opines that the Commonwealth can achieve approximately a 20% reduction in electricity consumption in a relatively short period of time – 3% in the first year, 6% within the next several years, and 20% shortly thereafter – at a low cost, simply by adopting a rate design with inclining blocks for residential customers (that is, persons using more energy being required to pay a higher rate for each marginal unit of electricity used) and installation of in-home displays. He, and his witness Mr. Jackson, contend that this is not a novel approach because it has been used in other states such as New Hampshire, California and Vermont. Mr. Vanderhye also maintains that the inclining block rate method (he recommends a format of 3 or

more tiers) would protect low income customers because it does not require the purchasing of additional equipment.

In Mr. Vanderhye's opinion, economic development will be enhanced in the Commonwealth through the use of block rates because this method will ensure that those with lower incomes have money to put back into the economy. He also opines that supplemental, voluntary DSM programs to encourage efficiency – associated with encouraging the purchase of energy efficient appliances – will enhance the economy.

F. Ice Energy, Inc.

Ice Energy, which develops and markets distributed energy storage and smart grid products, states that utilities can use new technology to reduce cost and avoid building additional infrastructure – and to incorporate renewable alternatives. Ice Energy advocates the Commission's use of the TRC test when determining the cost-effectiveness of DSM/efficiency programs.

G. Commission Staff

Staff explains that DSM/energy efficiency programs are “cost effective” when the cost of achieving efficiency (or reduced demand) is lower than the cost of forgone electric supply. Staff explains that most public utility commission proceedings relative to DSM and efficiency targets, previously undertaken by other states, have taken a longer amount of time than available in this proceeding and accordingly, certain “assumptions” must be made with respect to costs in order to make the determinations required by the statute. If such “assumptions” are changed, the results with respect to achievable DSM and efficiency programs will also change. Staff notes further that there are other related proceedings before the Commission dealing with Integrated Resource Plans, approval of specific DSM programs and smart meters/voltage conservation.

Staff discusses the various industry cost-effectiveness tests that have been advocated by the participants in this proceeding. Staff notes that both APCo and KU believe the TRC test should be given the greatest weight and that DVP has not advocated the use of a particular test when evaluating cost-effectiveness. Staff also notes that the TRC test is generally endorsed by proponents of DSM. In contrast, Staff explains that industrial groups favor the use of the RIM test to evaluate the cost-effectiveness of a DSM program.

Staff ultimately advocates that the Commission give greatest weight to RIM test. Staff questions whether the TRC test can be accurately performed due to uncertainties with respect to costs. Staff prefers the RIM test because it is based on objective factors – that is, changes in electric prices resulting from the implementation of DSM are the principal input into the RIM test and are readily identifiable. On the other hand, the TRC test is harder to accurately perform because it greatly depends on the performance of DSM measures. Staff holds that the performance of DSM measures (i.e. the ultimate cost of DSM when considered as an electric “resource”) is difficult to quantify.

The greater the cost of a DSM/efficiency program, the more likely such a program will result in customers paying higher rates for efficiency. In sum, DSM/efficiency goals are “achievable most cost-effectively through the use of price incentives that seek to incent customers to conserve electricity through using less and/or installing their own energy efficiency devices.”

Staff indicates that externalities – and, in particular, environmental factors – change the “assumptions” with respect to the cost-effectiveness of DSM/efficiency programs. Staff notes that consideration of quantifiable or unquantifiable environmental or other externalities, whether positive or negative, associated with the production and consumption of electric power versus the

production and consumption of energy efficiency greatly complicates the determination of what is or is not cost-effective.

Staff calculates a range of consumption and peak reductions (specifically, reductions of 5%, 10%, 15% and 20%) which could result from various price increases and be achieved by 2024. These hypothetical reductions in electric system use occur as customers react to higher electric rates. Staff does not advocate raising electric rates solely for the purpose of repressing electric demand. The information is provided to attempt to quantify the level of price increases required to achieve specified levels of electric usage reductions by 2024.

Staff notes that DVP and KU advocate that program costs be assigned to participating customer classes or jurisdictions and that APCo believes cost assignment should depend on the ultimate program selected and the number of large customers electing to opt-out of participation. Staff also indicates that although ratemaking is usually governed by “cost-causer” concepts, it may be difficult to ascertain exactly who benefits from various DSM/efficiency programs – noting that all customer classes would appear to benefit from environmental improvements.

With respect to DVP, Staff notes that the company believes it can reduce consumption (from 2006 levels) 10% by 2022 cost-effectively and that DVP recommends (1) basing any goal on historic consumption rather than projections and (2) using interim targets, fed into biennial IRPs, to assess achievability.

Staff believes DVP’s voltage conservation program constitutes a disproportionate share of its overall projected savings and costs of its DSM/efficiency portfolio and if the voltage conservation program does not function as the company anticipates, DVP will not reach its anticipated savings. Staff does not believe KU’s expectation of being able to save 1.2% of forecasted energy sales (in the period of between 2008 and 2014) is reasonably “aggressive,” and

suggests that KU could offer its Virginia customers some of the same DSM/efficiency options as are being provided in Kentucky and that rate impacts of such programs would be less for Virginia residents if they were permitted to share in the Kentucky program. If they are not permitted to share, the estimated costs of Virginia residents are estimated to be more than double what Kentucky residents can expect to pay associated with DSM/energy efficiency programs.

Staff notes that the APCo DSM Plan shows that a higher range of energy and demand reduction could be reached than what the company actually recommends. Specifically, the Summit Blue Study indicates that a consumption reduction of 3.07% and peak load reduction of 5.25% can be reached over a 5 year period at a cost of approximately \$134 million but that the company only recommends a 2% consumption reduction and 5% peak load reduction at a cost of from \$80 to \$100 million.

Staff questions whether the participation rates anticipated in the Summit Blue Study will be reached before we have achieved economic recovery. However, Staff believes that the overall targets set forth in the Summit Blue Study are “achievable.” Here “achievable” is defined as the target level of DSM achieved after taking into account the various barriers to the adoption of the energy efficient or demand reduction measures. While the Summit Blue Study usage reduction targets can be met, doing so will cost more, in terms of rate impacts, than the 2% consumption reduction and 5% peak reduction recommended by APCo.

H. MeadWestvaco Corporation

MeadWestvaco discusses the various industry recognized tests for determining the cost-effectiveness of DSM/efficiency programs and ultimately advocates the Commission’s use of the RIM test – stating: “Implementing measures that pass the RIM test will help avoid upward pressure on electricity rates.”

When discussing the “public interest” in the context of DSM/efficiency programs, MeadWestvaco maintains that it would be “fundamentally unfair and not in the public interest to ask industrial customers to fund energy efficiency improvements of their competitors’ facilities located in the same utility service territory or to create a competitive disadvantage for industries in Virginia that are competing with facilities in other states which have exempted their industrial customers.” Under the circumstances, MeadWestvaco asserts that the General Assembly acted appropriately when concluding that large industrial customers should be permitted to opt-out of DSM/efficiency programs.

With respect to determining the cost-effectiveness of programs available to customers who are not authorized to opt-out, MeadWestvaco advocates screening of each program for cost-effectiveness rather than evaluating the overall cost-effectiveness of a particular utility’s entire DSM/efficiency portfolio.

To determine a just and reasonable ratemaking methodology, MeadWestvaco recommends that the utilities be required to perform cost of service studies in support of rate actions. The company also recommends that the cost of DSM programs be allocated to the customer classes for which DSM programs are designed.

I. Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates

The Committees, which include a number of industrial customers in the DVP and APCo service territories, maintain that the General Assembly’s decision to provide an exemption/opt-out for large energy consumers is in the public interest because such customers do not face the same investment barriers to self-implementation of efficiency measures. They explain that they are interested in this proceeding to the extent that it may affect the scope of the opt-

out/exemption. They also indicate that economic development in the Commonwealth will be negatively impacted if the exemption/opt-out were to be eliminated.

The Committees do not recommend specific targets for the utilities but, instead, urge the Commission to consider certain factors when determining appropriate DSM/efficiency measures in the Commonwealth, that is:

- (a) the fact that non-utility measures (such as taxes, building codes, etc.) could have a greater impact on efficiency than utility administered programs;
- (b) the Commission should exercise caution in implementing financial commitments to be borne by customers; and
- (c) the Commission should not take industrial use into account when determining the cost-effectiveness of programs.

The Committees opine that the RIM test should be given the greatest weight when determining cost-effectiveness. The Committees also urge the Commission to consider the cost-effectiveness of each measure used in DSM programs—rather than evaluating the cost-effectiveness of the overall program or portfolio.

When determining whether a target is “achievable,” the Committees believe that the Commission should consider achievable potential taking into account likely customer action—as opposed to considering “technical potential” which relates to potential reductions regardless of cost or “economic potential” which considers potential savings to adopt cost-effective programs.

With respect to ratemaking, the Committees caution against the Commission taking a “simplistic approach” such as approving an across the board, volumetric surcharge billing method for DSM. To the extent that a particular program produces reduction in both consumption and peak demand, the Committees recommend that the cost of such a program be

divided between energy and demand charges. However, they acknowledge that this approach would not work for customers who are not “demand metered” – such as residential consumers.

J. Washington Gas Light Company

Washington Gas maintains that higher reductions can be achieved in energy consumption if the use of natural gas is considered for residential and commercial heating. The company also maintains that the use of natural gas for heating will reduce CO2 omissions. Similarly, Washington Gas asserts that impacts on the economy cannot be fully evaluated if the use of natural gas is not considered – and recognizes the potential for increased electricity use if the price of electricity is kept “artificially” low.

K. Virginia Energy Purchasing Governmental Association

VEPGA explains that its members are all non-jurisdictional customers of DVP that have negotiated rates and that have voluntarily implemented conservation and demand response measures on their own. It maintains that its members should not be obligated to participate in or bear responsibility for the general DSM/efficiency programs of DVP.

L. Piedmont Environmental Council

PEC urges the Commission to recommend higher targets than the 10% efficiency/conservation goal that has already been articulated. PEC disagrees with DVP’s conclusion that the potential reductions recognized in the ACEEE Report are overly aggressive.

PEC also indicates that it is generally supportive of the testimony of the SELC and of Mr. Vanderhye (in particular, it is supportive of the block rate approach discussed in Vanderhye/Jackson’s testimony). PEC maintains that generation and transmission alternatives for providing Virginia’s future energy needs require much greater investment than efficiency measures.

IV. Discussion

A. Achievable, Cost-Effective Conservation and Demand Response Targets

Chapter 888 of the 2007 Acts of the Virginia General Assembly included a finding that

it is in the public interest, and is consistent with the energy policy goals in § 67-102 of the Code of Virginia, to promote cost-effective conservation of energy through fair and effective demand side management, conservation, energy efficiency, and load management programs, including consumer education. These programs may include activities by electric utilities, public or private organizations, or both electric utilities and public or private organizations. *The Commonwealth shall have a stated goal of reducing the consumption of electric energy by retail customers through the implementation of such programs by the year 2022 by an amount equal to ten percent of the amount of electric energy consumed by retail customers in 2006.* [emphasis added]

The Commission thus begins its analysis from the assumption that the Commonwealth's existing policy, as directed by the General Assembly, holds that a ten percent electric energy consumption reduction by 2022 is achievable.¹¹ While some parties testified that additional reductions were achievable and desirable, no party presented evidence that the Commonwealth's existing legislative mandate regarding a reduction in electric energy consumption is unreasonable or unachievable. Any additional reduction in energy consumption by 2022, or any acceleration in the timetable for achieving the existing ten percent energy consumption reduction target, could potentially come at substantially higher rates to consumers. The Commission recognizes that existing retail electric rates have been increasing significantly for Virginia consumers in the last several years, and thus any decision to increase existing targets or accelerate achieving existing mandates has the potential to create additional upward rate

¹¹ The Commission's Staff previously concluded in a Staff Report dated November 16, 2007 ("2007 DSM Report") that the General Assembly's stated goal of a 10% energy consumption reduction by the year 2022 was attainable. In accordance with Enactment Clause 3 of Chapters 888 and 933 of the 2007 Acts of Assembly, the Commission transmitted the 2007 DSM Report to the Governor and General Assembly by letter dated December 14, 2007.

pressure. Again, however, the Commission notes that nothing in the record before it suggests that the existing targets or timetable are unachievable.

As noted by the parties before the Commission, however, substantial questions remain regarding achievement of the existing legislative target. For example, how should actual reductions in peak load and consumption be tracked, and how should such reductions be compared to forecast reductions? How should the cost of achieving such reductions be calculated and how should such costs be tracked? Should load reductions be phased in over time over the course of the next 13 years, and if so, according to what schedule for phase-in?

Finally, with respect to specific individual consumption and peak load reduction targets for Virginia's electric utilities, the Commission recognizes that the development of such targets will require more time and analysis than was available for this Report, and would necessitate more evidence than was presented to the Commission in this proceeding. Should the General Assembly so desire, the Commission will continue its work to provide more specificity.

B. Range of Potential Consumption and Peak Load Reductions

The General Assembly directed the Commission to report on "the range of consumption and peak load reductions that are potentially achievable by each generating electric utility, the range of costs that consumers would pay to achieve those reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 15-year period." To that end, Commission Staff requested that each utility provide information regarding achievable energy and peak load reductions and the cost to ratepayers associated with such reductions. Staff requested that each utility provide data for energy and peak load reductions from five percent to twenty percent in 2024.

DVP informed Staff that a 2.8% decrease in energy sales versus the kWh sales level that would otherwise prevail in 2024 was estimated by the company to cost \$2.073 billion for a portfolio of energy efficiency and demand response programs and would raise rates to consumers about one-quarter of one cent per kWh. For reductions in excess of 2.8%, DVP tendered energy reductions, dollars spent and rate impacts for Florida Power and Light programs offered from 1992 through 2007. These results are summarized in the following table:

	2.8%	5.0%	10.0%	15.0%	20.0%
<i>Energy Reduction</i>					
Program Cost	\$ 1,227,516,000	\$ 1,596,265,000	\$ 3,192,530,000	\$ 4,788,796,000	\$ 6,385,061,000
Saved 2024 MWH	3,165,148	5,652,050	11,304,100	16,956,150	22,608,200
Rate Impact (per kWh)	\$ 0.0024	\$ 0.0150	\$ 0.0330	\$ 0.0520	\$ 0.0730
Bill Impact (per 1000 kWh)	\$ 2.40	\$ 15.00	\$ 33.00	\$ 52.00	\$ 73.00
New Bill	\$ 111.29	\$ 123.89	\$ 141.89	\$ 160.89	\$ 181.89
Old Bill	\$ 108.89	\$ 108.89	\$ 108.89	\$ 108.89	\$ 108.89
<i>Capacity Reduction</i>					
Program Cost	\$ 845,772,000	\$ 1,885,407,000	\$ 3,770,815,000	\$ 5,656,222,000	\$ 7,541,630,000
Saved 2024 MW	631	1,101	2,203	3,304	4,405
Rate Impact (per kWh)	\$ 0.0024	\$ 0.0170	\$ 0.0350	\$ 0.0520	\$ 0.0690
Bill Impact (per 1000 kWh)	\$ 2.40	\$ 17.00	\$ 35.00	\$ 52.00	\$ 69.00
New Bill	\$ 111.29	\$ 125.89	\$ 143.89	\$ 160.89	\$ 177.89
Old Bill	\$ 108.89	\$ 108.89	\$ 108.89	\$ 108.89	\$ 108.89

In April 2008, KU received approval to implement a range of DSM programs in Kentucky. In response to Staff's inquiry, KU estimated costs in Virginia using Kentucky data converted to its much smaller Virginia service territory, summarized in the following table:

<u>Energy Reduction</u>		<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
Program Cost		\$ 19,261,925	\$ 38,523,851	\$ 57,785,776	\$ 77,047,701
Saved 2024 MWH		52,573	105,146	157,719	210,292
Rate Impact (per kWh)	Res	\$ 0.030	\$ 0.061	\$ 0.091	\$ 0.122
Rate Impact (per kWh)	Com	\$ 0.009	\$ 0.018	\$ 0.027	\$ 0.037
Bill Impact (per 1000 kWh)	Res	\$ 30.00	\$ 61.00	\$ 91.00	\$ 122.00
	New Bill	\$ 99.91	\$ 130.91	\$ 160.91	\$ 191.91
	Old Bill	\$ 69.91	\$ 69.91	\$ 69.91	\$ 69.91
<u>Capacity Reduction</u>		<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
Program Cost		\$ 14,006,019	\$ 28,012,038	\$ 42,018,057	\$ 56,024,076
Saved 2024 MWH		12.5	25	37.5	50
Rate Impact (per kWh)	Res	\$ 0.022	\$ 0.045	\$ 0.067	\$ 0.090
Rate Impact (per kWh)	Com	\$ 0.006	\$ 0.013	\$ 0.019	\$ 0.026
Bill Impact (per 1000 kW)	Res	\$ 22.00	\$ 45.00	\$ 67.00	\$ 90.00
	New Bill	\$ 91.91	\$ 114.91	\$ 136.91	\$ 159.91
	Old Bill	\$ 69.91	\$ 69.91	\$ 69.91	\$ 69.91

Unlike KU and DVP, APCo did not respond directly to Staff's request, but indicated that a savings of approximately 2% of APCO's 2008 Virginia energy consumption and approximately 5% of its 2008 peak load would cost approximately \$80-100 million for direct program and administrative costs. Additional reductions would be achievable at a higher cost.

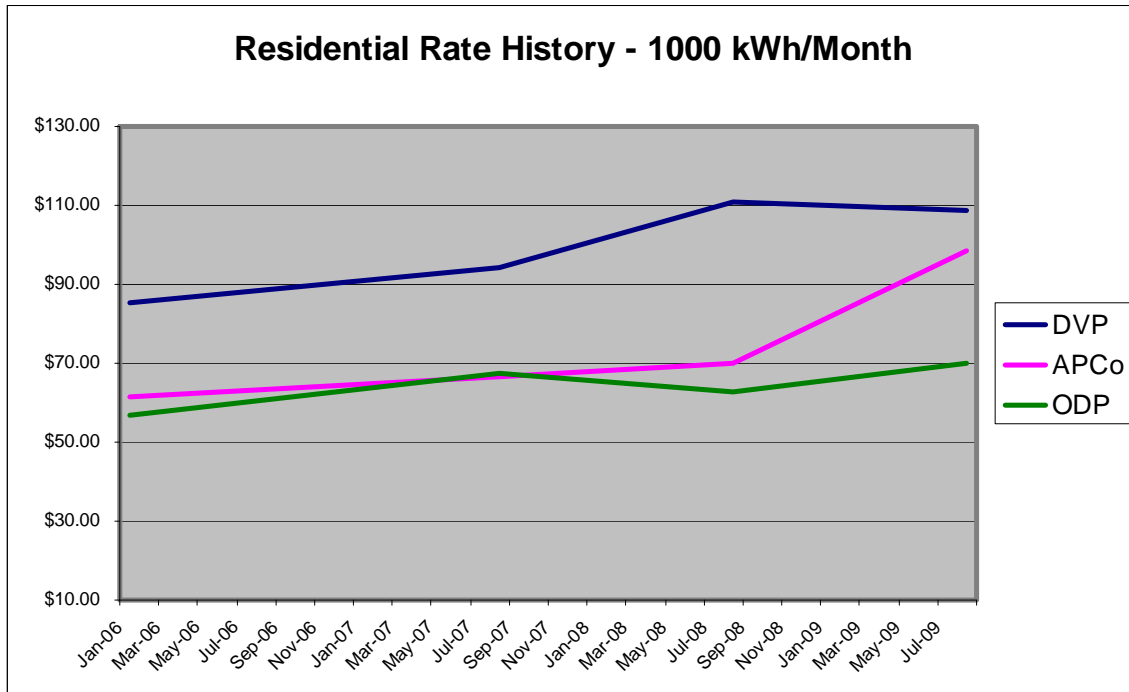
Thus, absent the quantification of potential offsetting savings, a 10% reduction in energy consumption by 2024 would increase the overall bill of a residential DVP customer using 1000 kWh per month from \$108.89 per month to \$143.89 per month. A similar customer served by

KU would see an increase from \$69.91 to \$114.91. A 20% reduction in energy consumption would increase the DVP customer's bill to \$177.89 per month, and the KU customer's bill to \$159.91.

These rate increases resulting from reductions in energy consumption through DSM programs would be in addition to a number of recent rate increases. From January 2006 to August 2009, an average residential user consuming 1000 kWh per month has seen rate increases ranging from 22.84% to 60.52%:

Utility	Rate as of 8/10/2009	Increase Since 1/1/2006
DVP	\$108.89	27.69%
APCo	\$ 98.53	60.52%
KU/ODP	\$ 69.91	22.84%

These increases are presented below by utility in graphical form.



The rates referenced above do not include a number of proceedings decided after August 2009 or pending at the Commission as of the date of this Report, some of which have the potential to increase rates even more.¹² Some of these matters include increased rates now being paid by consumers on an interim basis pending final Commission determinations. For example, effective November 1, 2009, in Case No. PUE-2009-00029, Old Dominion Power Company increased rates on an interim basis by 30.8%. Furthermore, a number of these proceedings involve rate adjustment clauses that will be supplemented annually, with corresponding rate changes each year.

Based on the evidence presented in this matter and the time allotted for analysis, the Commission cannot conclude that the estimates of Virginia's generating electric utilities regarding ranges of potentially achievable consumption and peak load reductions at particular costs are inaccurate at this time. The Commission also notes, however, that despite its request the relevant utilities did not provide sufficient information regarding the potential financial benefits associated with various ranges of consumption and peak load reductions. We recognize that the SELC argued in its brief that the cost of efficiency programs, per kilowatt hour, is less expensive than the cost of building additional generation such as DVP's Wise County coal plant. However, sufficient evidence was not presented in this proceeding for us to reach such a factual conclusion. Under the circumstances, while the Commission is aware that there may well be offsetting cost benefits from DSM programs, attempting to quantify these benefits in specific detail

¹² See *Appalachian Power Company*, Case No. PUE-2009-00030 (base rate case, 17.1% rate increase requested); *Appalachian Power Company*, Case No. PUE-2009-00031 (transmission cost rate adjustment clause, 1.8% rate increase approved October 6, 2009); *Appalachian Power Company*, Case No. PUE-2009-00039 (environmental and reliability cost recovery, 3.6% rate increase requested); *Virginia Electric and Power Company*, PUE-2009-00011 (rate adjustment clause for costs related to the Virginia City Hybrid Energy Center, 1.7% rate increase requested); *Virginia Electric and Power Company*, PUE-2009-00017 (rate adjustment clause for costs related to the Bear Garden Generating Station, 1.2% rate increase requested); *Virginia Electric and Power Company*, PUE-2009-00019 (base rate case, 5.1% rate increase requested); *Virginia Electric and Power Company*, PUE-2009-00081 (rate adjustment clauses for peak shaving and energy efficiency programs, 0.9% rate increase requested).

would be speculative at this time given the limited amount of evidence that was presented in the Commission's proceeding.

C. Cost Benefit Test

Chapter 855 directed the Commission to “determine which [industry standard] test should be given greatest weight when preparing a cost-benefit analysis of a demand-side management program, taking into consideration the public interest and the potential impact on economic development in the Commonwealth.” As noted by Dominion, the Commission's existing DSM policy includes four industry standard tests that may be used in such a cost-benefit analysis: (1) the RIM test, (2) the TRC test, (3) the Participant test, and (4) the Utility Cost test (these tests are defined in Section II of this Report). It is the opinion of the Commission that the RIM Test, which focuses on the impact on customer rates, generally fits with the Commission's existing statutory mandate to ensure just and reasonable rates. However, the Commission also believes that the evidence demonstrates that the TRC Test, which considers matters other than the direct impact on rates, is appropriate to consider, provided that the underlying assumptions are based on objective and verifiable data. Therefore, in evaluating programs under existing statutes, the Commission will normally apply the RIM Test, the TRC Test, or some combination of the two as appropriate. Consistent with the Commission's existing DSM Rules, the data from the Participant and Utility Cost tests should also be explored to fully evaluate any DSM proposal.

Most importantly, while the Commission has evaluated energy efficiency targets and benefits in the abstract herein as directed by its statutory mandate, any evaluation of specific utility DSM proposals, such as the programs proposed by Dominion in case number PUE-2009-00081, will be done on a case-by-case basis, applying all relevant statutory authority.

In sum, consistent with our general statutory duty, the Commission will give greatest weight to the RIM test, closely followed by the TRC test and rounded out by consideration of the Participant and Utility Cost tests. Ultimately, flexibility is needed to ensure that impacts on ratepayers are fully considered along with the overall public interest. The Commission, of course, stands ready to implement any policy decision the General Assembly may deem appropriate. Ultimately, the choice of which of the various tests should be emphasized could be considered a policy decision, which is embedded in the statutes governing the Commission.

D. Rate Design

The Commission believes that the evidence presented to it demonstrates that ratemaking methodology and rate structure (which may be considered together as rate design) may be effective in reducing peak demand and energy consumption. In general, Virginia law and Commission precedent encourage application of the principle of cost causation, whereby the customer or class of customers incurring costs or requiring action are responsible for paying such costs. The Commission received no credible evidence during the course of this proceeding to suggest that the general principle of cost causation is inappropriate for application to energy efficiency or demand-side resources. Thus, barring specific policy direction from the General Assembly, the Commission shall continue to apply traditional ratemaking principles on a case-by-case basis to individual proposals filed by the utilities with the Commission.

We received evidence that rate design methods, including inclining block rates, can affect demand. Quantifying specific demand reductions over a specific number of years, however, as well as quantifying the rate impact on consumers, requires significantly more detailed information about specific rate design models than was available to us in the time frame of this proceeding. Furthermore, different rate design models each have different impacts on

consumers. The Commission currently has the legal authority to approve and order changes to rate design models, and the Commission exercises that authority in the context of its existing statutory framework which directs it generally to pursue retail rates that are just to utilities and reasonable to consumers. The question of whether different retail rate designs (or other conservation and efficiency programs) should be implemented that elevate demand reduction as a goal is ultimately a question of policy that should not be implemented absent careful consideration of the rate and general economic impacts on residential, business and industrial consumers.

Finally, Chapter 855 also requires the Commission to “examine other jurisdictions that permit certain nonresidential customers or classes of customers to either be exempt from paying for the utility DSM programs or to opt out of participating in or paying for the utility DSM programs, and determine if it would be in the public interest for the Commonwealth to have a similar policy.” Commission Staff presented some analysis to the Commission regarding jurisdictions that allow such opt-out. However, the Commission notes that the General Assembly revised § 56-585.1 of the Code of Virginia to provide that “[n]one of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, shall be assigned to any customer that has a verifiable history of having used more than 10 megawatts of demand from a single meter of delivery. Nor shall any of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, be incurred by any large general service customer as defined herein that has notified the utility of non-participation in such energy efficiency program or programs.” The Commission is currently considering the rules necessary to implement the mandate that large customers be permitted to opt out of paying the costs of utility DSM programs.

Therefore, the Commission believes that the question of whether large customers should be permitted to opt out of paying the costs of utility DSM programs is moot at this time. Should the General Assembly wish for the Commission to evaluate whether additional changes to § 56-585.1 are feasible, or what the impact on ratepayers would be should the existing policy directive to allow such opt-out be changed, the Commission will undertake such analysis at that time.

V. Conclusions and Further Steps

As noted above, the Commission did not receive any evidence demonstrating that the existing policy of the Commonwealth regarding reduction in consumption through DSM, DR and energy efficiency programs is unrealistic or unachievable. We have considered a number of factors in preparing this Report, including the magnitude of recent rate increases borne by ratepayers,¹³ and while we acknowledge that additional reductions in electricity consumption through DSM programs appear to be possible, such reductions could potentially come at additional cost to ratepayers. We also recognize that there are potential offsetting cost savings associated with efficiency programs that result in the reduction of energy consumption and peak load; however, attempting to quantify with specificity such cost savings based on the record before us would be speculative.

Absent any change in the statutory framework that governs Commission proceedings, the Commission will give the greatest weight to the RIM and TRC Tests, which are the most consistent with the Commission's current statutory mandates, in evaluating the costs and benefits of specific utility proposals. Consistent with the Commission's existing DSM Rules, the data from the Participant and Utility Cost tests should also be explored to fully evaluate any DSM proposal.

¹³ See Charts on page 30 of this Report.

Due in large part to time constraints and the resulting limited evidence presented in the Commission's proceeding, current economic conditions and rate impact implications, the Commission is not recommending herein any specific mandate to utilities regarding particular targets to be achieved, programs to be required, specific technologies to be used, or narrowly-tailored analyses to be performed. Unless otherwise directed by the General Assembly, the Commission will evaluate proposals on a case-by-case basis, under the applicable statutes, and anticipates that each utility will work toward achieving the Commonwealth's stated consumption reduction goal individually, with programs and technologies tailored to the specific need of the utility and its customers.

Furthermore, while the analysis contained herein has been general by necessity given the abbreviated schedule required by the statute, the Commission is open to further analysis should the General Assembly so direct. Such analysis could include the interplay of energy efficiency and DSM with other Commonwealth policy, such as integrated resource planning or gas decoupling; additional analysis of rate design methodology and the impact of changes in rate design on energy consumption; assessment of utility bill presentation and any impact on consumption from changes in the amount or quality of information presented to customers; or interim analysis of consumption and peak load reductions, and proposals regarding revision of the ten percent goal previously established by the General Assembly.

Commonwealth of Virginia
State Corporation Commission

**Report to the Governor of the Commonwealth of Virginia
and the Virginia General Assembly**



**Report: Study to Determine Achievable and Cost-effective
Demand-side Management Portfolios Administered
by Generating Electric Utilities in the Commonwealth**

**Pursuant to Chapters 752 and 855 of the
2009 Acts of the Virginia General Assembly**

**Volume 2
Appendices**

November 15, 2009

Report: Study to Determine Achievable and Cost-effective
Demand-side Management Portfolios Administered
by Generating Electric Utilities in the Commonwealth

SCC Case No. PUE-2009-00023

Volume 2
Appendices

Virginia Electric and Power Company
Appalachian Power Company
Kentucky Utilities d/b/a Old Dominion Power Company
Southern Environmental Law Center
Mr. Robert Vanderhye
Ice Energy, Inc.
Commission Staff
Meadwestvaco Corporation
Virginia Committee for Fair Utility Rates and the
Old Dominion Committee for Fair Utility Rates
Washington Gas Light Company
Virginia Energy Purchasing Governmental Association
Piedmont Environmental Council
Virginia Electric Cooperatives

Dominion Resources Services, Inc.
Law Department
P.O. Box 26532, Richmond, VA 23261



M. Renae Carter
Senior Counsel
Direct: (804) 819-2691
Fax: (804) 819-2183

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Joel H. Peck, Clerk
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State Corporation Commission
Tyler Building, 1st Floor
1300 East Main Street
Richmond, VA 23219

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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly Case No. PUE-2009-00023

Dear Mr. Peck:

Pursuant to Ordering Paragraphs (3) and (8) of the Commission's April 30, 2009, Order Establishing Proceeding and Setting Evidentiary Hearing in the above referenced case, please find enclosed for filing on behalf of respondent Virginia Electric and Power Company an original and fifteen (15) copies of its Direct Testimony.

If you should have any questions, please do not hesitate to contact me.

Sincerely,

A handwritten signature in cursive script that reads "M. Renae Carter".

M. Renae Carter

Enclosure

cc: Don R. Mueller, Esq.
Frederick D. Ochsenhirt, Esq.
Service List

CERTIFICATE OF SERVICE
CASE NO. PUE-2009-00023

I hereby certify that a true copy of the foregoing was hand delivered or mailed first class mail, postage prepaid on this 30th day of June 2009, to the following:

C. Meade Browder, Jr., Esq.
Office of the Attorney General
Division of Consumer Counsel
900 East Main Street, 2nd Floor
Richmond, Virginia 23219

Patrick R. Scanlon, Esq.
Preti, Flaherty, Beliveau & Pachios
45 Memorial Circle
P. O. Box 1058
Augusta, ME 04332

Todd J. Griset, Esq.
Preti, Flaherty, Beliveau & Pachios
45 Memorial Circle
P. O. Box 1058
Augusta, ME 04332

Irene A. Kowalczyk, Director
Energy Policy & Supply
MeadWestvaco Corporation
299 Park Avenue, 13th Floor
New York, NY 10171

Donald J. Sipe, Esquire
Preti, Flaherty, Beliveau & Pachios
45 Memorial Circle
Augusta, ME 04332

Kendrick R. Riggs, Esq.
Stoll, Keenon, Ogden
2000 PNC Plaza
500 West Jefferson Street
Louisville, KY 40202-2828

Louis R. Monacell, Esq.
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219-3095

Edward L. Petrini, Esq.
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219-3095

Mr. Robert A. Vanderhye
801 Ridge Drive
McLean, VA 22101-1625

Chris S. King
Chief Strategy Officer
eMeter Corporation
2215 Bridgepointe Parkway, Suite 300
San Mateo, CA 94404

Jack Greenhalgh, President
New Era Energy
P. O. Box 121
Williamsburg, VA 23090

Caleb Jaffe
Southern Environmental Law Center
201 West Main Street, Suite 14
Charlottesville, VA 22902

Anthony J. Gambardella, Jr.
Woods Rogers
823 East Main Street, Suite 1200
Richmond, VA 23219

Barry L. Thomas
Director, Regulatory Affairs
American Electric Power Co.
1051 East Cary Street, Suite 702
Richmond, VA 23219

W. Todd Benson, Esquire
Piedmont Environmental Council
P. O. Box 460
Warrenton, VA 20188

Cliona M. Robb, Esq.
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219

Meera Ahamed, Esq.
Washington Gas Light Company
101 Constitution Avenue, NW
Washington, DC 20080

Richard D. Gary, Esq.
Noelle C. Coates, Esq.
Hunton & Williams, LLP
Riverfront Plaza, East Tower
951 East Byrd Street
Richmond, VA 23219-4074

Sarah Rispin
Southern Environmental Law Center
201 West Main Street, Suite 14
Charlottesville, VA 22902-5065

David Prezioso
Vice President
Ice Energy Corporation
1357 Linley Trace
Marietta, GA 30056

M. Renae Carter

Counsel

Direct Testimony of
Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

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 electric utility
Identified by Chapters 752 and 855 of the 2009
Acts of the Virginia General Assembly
Case No. PUE-2009-00023

Filed: June 30, 2009

**DIRECT TESTIMONY
OF
SHANNON L. VENABLE
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2009-00023**

1 **Q. Please state your name, business address, and position with Virginia Electric and**
2 **Power Company (“Dominion Virginia Power” or the “Company”).**

3 A. My name is Shannon L. Venable and my business address is 120 Tredegar Street,
4 Richmond, Virginia, 23219. I am the Vice President of Integrated Resource Planning for
5 Dominion Virginia Power. I am responsible for the development of initiatives that
6 integrate capacity plans and demand-side resources in support of the Company’s
7 regulatory initiatives. As part of my duties, I also oversee the Company’s peak demand
8 and energy forecasts over a 15-year period and the design, development, and evaluation
9 of demand-side management (“DSM”) programs. As used in my testimony, DSM means
10 energy conservation and demand response programs. A statement of my background and
11 qualifications is attached as Appendix A.

12 **Q. Mrs. Venable, would you please discuss the purpose of the Company’s filing?**

13 A. During the 2009 Session, the Virginia General Assembly enacted Chapter 752 (House
14 Bill 2531) and Chapter 855 (Senate Bill 1348) of the 2009 Acts of the Assembly (the
15 “Legislation”). The Second Enactment Clauses of the Legislation provide that the State
16 Corporation Commission (“Commission”) shall conduct a formal public proceeding that
17 will include an evidentiary hearing to determine achievable, cost-effective energy
18 conservation and demand response targets that can realistically be accomplished in the

1 Commonwealth through DSM portfolios administered by each generating electric utility
2 in the Commonwealth. The determination of what consumption and peak load reductions
3 can be achieved cost-effectively shall consider standard, industry-recognized tests. The
4 Commission shall also determine which test should be given greatest weight when
5 preparing a cost-benefit analysis of a demand-side management program, taking into
6 consideration the public interest and the potential impact on economic development in the
7 Commonwealth. The Commission is also required to report its findings to the Governor
8 and the General Assembly on or before November 15, 2009.

9 Pursuant to the Legislation, on April 30, 2009, the Commission issued an *Order*
10 *Establishing Proceeding and Setting Evidentiary Hearing* (“Order”) in this proceeding.

11 In its Order, the Commission established a procedural schedule and, based on the
12 definition of a generating electric utility contained in the Legislation, named the
13 Company, Appalachian Power Company, and Kentucky Utilities Company d/b/a Old
14 Dominion Power Company as respondents in this proceeding. The Commission also
15 directed that all respondent generating electric utilities file testimony (and any supporting
16 legal briefs) addressing nine specific questions contained in the Order (the
17 “Commission’s Questions”).

18 The primary purpose of my testimony is to sponsor the Company’s most recent 15-year
19 load forecast used in preparation of its Integrated Resource Plan (the “Plan”) in response
20 to Commission Question No. 1. Additionally, on behalf of Dominion Virginia Power, I
21 will address the Company’s response to each of the Commission’s Questions. I will also
22 address the general policy question of what are “achievable, cost-effective energy
23 conservation and demand response targets that can realistically be

1 accomplished...through demand-side management portfolios administered by each
2 generating electric utility in the Commonwealth” contained in the Legislation.

3 **Q. Are you sponsoring any exhibits or schedules in connection with your testimony?**

4 A. Yes. Company Exhibit No. __, SLV, Schedule 1 contains the Company’s most recent
5 15-year load forecast, which will serve as the basis for the Company’s first biennial Plan
6 to be filed on September 1, 2009. The Company must file its Plan with the Commission
7 by September 1, 2009, pursuant to § 56-599 B of the Code and the Commission’s
8 December 23, 2008, *Order Establishing Guidelines for Developing Integrated Resource*
9 *Plans* issued in Case No. PUE-2008-00099. I will discuss the Company’s 2009 Plan in
10 detail later in my testimony. The Company also intends to use this forecast for its initial
11 offering of a portfolio of DSM programs (individually “DSM Program” or “Program”
12 and collectively “DSM Portfolio” or “Portfolio”) to be filed shortly.

13 **SECTION I: DSM TARGETS**

14 **Q. Commission Question No. 1 asks “What is an achievable, cost-effective energy**
15 **conservation and demand response target that can be realistically accomplished**
16 **through the generating electric utility’s demand-side management portfolio?”**
17 **Would you please comment?**

18 A. Yes. The Company believes that a ten percent goal using a 2006 base year is an
19 aggressive but realistically accomplishable target toward maximizing cost-effective DSM
20 programs in Virginia. The Company’s position is consistent with previous Commission
21 conclusions, the Virginia Energy Plan, and determinations by the General Assembly. On
22 December 14, 2007, the Commission provided the Governor and the members of the
23 General Assembly with the results of the Commission Staff’s Report, which concluded

1 that the ten percent goal is attainable. The 2007 Virginia Energy Plan also supports the
2 ten percent goal. Moreover, the General Assembly in Enactment Clause 3 to Chapters
3 888 and 933 of the 2007 Acts of the Assembly set a goal to reduce, by 2022, electric use
4 by ten percent of 2006 retail consumption through conservation and energy efficiency
5 (the “10 Percent Goal”).

6 The Company believes that the 10 Percent Goal is attainable and notes that achieving this
7 goal is dependent upon the goal being based on actual historical energy usage and
8 demand using a given base year such as 2006 rather than being based on reductions of
9 future projections of growth for which results would be difficult to measure and difficult
10 to understand if and when the goal is met.

11 **Q. Why is a base year important?**

12 A. The use of a base year represents the actual energy and demand of customers for a given
13 year and for given, known circumstances. Effects due to the economy, weather, and
14 other technological factors can be more easily identified so that future reductions can be
15 more readily supported and identified. Reductions that are based on future forecasts have
16 a level of uncertainty due to changes in the economy, weather, technologies (e.g., plug-in
17 hybrid electric vehicles), appliance standards, building standards, etc. that could
18 significantly increase or decrease usage and demand in the future, making it difficult to
19 determine if the goals have been achieved. Thus, the Company urges that the use of
20 actual data for the 2006 base year be the basis of measuring performance of any goals
21 that are established through this proceeding.

1 **Q. Does the Company suggest that interim targets be used along the way in meeting the**
2 **10 Percent Goal?**

3 A. Yes. It should be noted that any target that may be considered achievable and cost-
4 effective at this point in time does not take into account other factors such as changes in
5 the law including carbon regulation, changes in the economy, the commercial availability
6 of future technologies, or other unknown factors. In light of these uncertainties, the
7 Company believes that interim targets or milestones be used to continue to assess both
8 “achievability” and “cost-effectiveness” related to meeting the long-term targets. The
9 Company believes that each utility should report results of program implementations and
10 actual costs. This report could potentially be included as part of each utility’s integrated
11 resource planning process, which would allow for targets to be assessed on a biennial
12 basis to determine whether the overall energy conservation and demand response targets
13 need to be adjusted. Again, the Company believes that this would not only provide on-
14 going validation of the short-term investments and reductions, but also ensure these
15 investments can support the longer-term target and help all parties better understand the
16 cost impacts to all customers.

17 **Q. Does the Company intend to meet the 10 Percent Goal?**

18 A. Yes. As the Commission is aware, on March 31, 2009, the Company filed a Revised
19 Notice of Intent To File a Petition Pursuant to § 56-585.1 A 5 of the Code of Virginia
20 (“Va. Code”) advising the Commission of its intent to file a petition for approval of DSM
21 Programs on or after July 1, 2009. In this filing, the Company will be proposing a
22 Portfolio of DSM Programs that is cost-effective and designed to achieve reductions in
23 energy and capacity over a 15-year period. The Company designed this initial Portfolio

1 to begin pursuing the already established 10 Percent Goal, and it will provide a
2 significant first increment, achieving approximately one-third of the 10 Percent Goal.
3 This initial offering includes industry-accepted Programs with an existing market base
4 and proven technologies. To achieve further increments towards achieving the 10
5 Percent Goal, the Company intends to propose additional cost-effective programs in the
6 future.

7 **Q. Is the Company aware of any studies where targets similar to the 10 Percent Goal**
8 **have been agreed upon by other entities?**

9 A. The Company notes that there is no single agreed upon target by regulators, utilities,
10 environmentalists, or customers for energy conservation and reduction for any particular
11 year. However, in January 2009, the Electric Power Research Institute (“EPRI”) released
12 a study titled the “Assessment of Achievable Potential from Energy Efficiency and
13 Demand Response Programs in the U.S.” (“EPRI Study”). The EPRI Study assesses the
14 achievable potential for energy efficiency and demand response programs to reduce the
15 growth rate in electric consumption and peak demand for the period from 2010 to 2030.
16 The EPRI Study states that the “range of achievable potential in electric consumption in
17 2030 – from a “moderate case” or *realistic achievable potential* of 8% to a “high case” or
18 *maximum achievable potential* of 11%” (EPRI Study, Page x) using a 2008 base year.
19 Although the Company believes the range stated in the EPRI Study is reasonable, the
20 Company also believes that a specific targeted number, as opposed to a range, should be
21 utilized to simplify reporting of the results of energy efficiency measures.

22 **Q. Is the Company aware of any studies that may be overly ambitious or unattainable**
23 **on the levels of achievable DSM?**

1 A. Yes. The American Council for an Energy-Efficient Economy (“ACEEE”) released a
2 report titled “Energizing Virginia: Efficiency First” (“ACEEE Report”) in September
3 2008. As the Company understands the ACEEE Report, it deems a measure as being
4 “cost-effective” if the levelized cost of conserved energy for the measure is less than
5 \$0.10/kWh, which is ACEEE’s estimate of the average retail residential price for
6 electricity in Virginia. This may be an indicator of the degree to which an individual
7 participant could benefit from the measure, but it is not an indicator of the value to the
8 utility or ratepayers who are not participants in the programs. This differs from the
9 Company’s view that programs should be measured against the Company’s load shape,
10 which evaluates a program’s benefits and costs versus the marginal avoided cost during
11 peak and non-peak periods. The Company then evaluates a program’s cost effectiveness
12 based on the results of four cost/benefit tests, which I will discuss later. The Company is
13 also unsure whether the ACEEE Report reflects the cost of designing, marketing,
14 implementing, and evaluating energy efficiency programs. As a result, the Company
15 believes the ACEEE Report’s findings are overly ambitious with regard to achievable
16 DSM levels.

17 **Q. Please summarize the Company’s position on what is an achievable, cost-effective**
18 **energy conservation and demand response target.**

19 A. The Company believes that the already established 10 Percent Goal using the base year of
20 2006 can be realistically accomplished in a cost-effective manner. The Company also
21 believes interim targets potentially incorporated into the Company’s integrated resource
22 plan should be set to provide on-going validation of reductions.

1 Company believes the “public interest” standard should be applied to a total portfolio of
2 DSM programs rather than to individual DSM programs, and whether or not an
3 individual program “passes” any particular cost-benefit Test (score of > 1.0) is not
4 dispositive as to whether the overall portfolio is in the public interest and should be
5 implemented. The Company believes that there are important non-price criteria that need
6 to be considered when determining whether or not DSM programs are in the public
7 interest. The Company also believes that this position is consistent with public policy in
8 the Commonwealth. For example, the Second Enactment Clause of Chapter 603 of the
9 2008 Acts of Assembly (“House Bill 1523”), which created Chapter 24 of Title 56 of the
10 Va. Code, states:

11 That as part of its 2009 integrated resource plan developed
12 pursuant to this act, each electric utility shall assess governmental,
13 nonprofit, and utility programs in its service territory to assist low
14 income residential customers with energy costs and shall examine,
15 in cooperation with relevant governmental, nonprofit, and private
16 sector stakeholders, options for making any needed changes to
17 such programs.

18 [Emphasis added.]

19 In addition, pursuant to § 56-585.1 A 5 c, the General Assembly has stated that besides
20 considering the public interest, “In all relevant proceedings pursuant to this section, the
21 Commission shall take into consideration the goals of economic development, energy
22 efficiency and environmental protection in the Commonwealth.”

23 It is clear that the General Assembly has determined that certain actions, such as assisting
24 low income customers, promoting economic development, and protecting the
25 environment are in the “public interest.” The Company has designed its DSM Portfolio
26 to be not only attractive to consumers in terms of financial payback, technological

1 availability, ease of installation, and lifestyle considerations, but the Company believes
2 that its energy conservation programs help promote other goals identified by the General
3 Assembly, such as assisting low income customers, promoting economic development
4 and energy efficiency, and protecting the environment, while being part of an overall
5 cost-effective portfolio.

6 SECTION III: DEFINITIONS

7 **Q. Commission Question No. 3 asks “How should the Commission define the terms**
8 **‘achievable,’ ‘cost-effective,’ and ‘be realistically accomplished’ as they are used in**
9 **the Legislation?” Does the Company have a position on these definitions?**

10 A. The phrasing of “achievable, cost-effective” conservation and demand-side targets “that
11 can reasonably be accomplished” appears to be a purposeful recognition by the General
12 Assembly that “achievable” conservation cannot be considered without also balancing the
13 cost of such programs. Therefore, the issue to be considered by the Commission is not
14 only whether reductions are “achievable” in an absolute sense, but whether they are
15 achievable relative to cost and relative to being acceptable to customers. Additionally,
16 the Commission should also consider the short- and long-term impacts to customers.
17 Although a DSM portfolio or program may be cost-effective over the life of the portfolio/
18 program based on the Tests, the initial cost to customers may make it impractical to
19 implement (e.g., customers may not accept a payback of more than one or two years, and
20 the program life could be five to seven years).

21 The Company also notes that some of the conservation efforts must be accomplished
22 outside of the utility’s sphere of influence. For example, page 58 of the Virginia Energy
23 Plan states that energy-efficiency and conservation programs can include many strategies

1 including: 1) consumer education; 2) training for service and design professionals;
2 3) financial incentives that influence consumers' decisions; 4) increasing energy-
3 efficiency building and equipment standards; 5) utility rates and programs; 6) research
4 and development programs; and 7) transportation improvements and mass transit
5 incentives. Additionally, the Governor has issued Executive Orders 48 and 82 directing
6 the coordination of energy activities among private organizations and state agencies and
7 institutions. As part of these initiatives, the Governor promotes energy and water
8 efficient buildings, encourages reductions in employee travel and commuting, and
9 minimizes the use of disposable materials.

10 **Q. Are there any related terms that should be defined as part of establishing**
11 **achievable, cost-effective targets?**

12 A. The EPRI Study included a definition of three categories to assist in determining the
13 range of achievable energy efficiency and demand response potentials. The categories
14 included technical potential, economic potential, and achievable potential.

15 Technical potential “represents the savings due to energy efficiency and demand response
16 programs that would result if all homes and businesses adopted the most efficient,
17 commercially available technologies and measures, *regardless of cost*” (EPRI Study,
18 Page xiii). EPRI defined this as the largest definition of savings since it encompasses “all
19 current equipment, processes, and practices in all sectors of the market” (EPRI Study,
20 Page xiii). Additionally, it should be noted that technical potential does not include the
21 “cost-effectiveness of the measures or the rate of market acceptance of those measures”
22 (EPRI Study, Page xiii).

1 Economic potential “represents the savings due to programs that would result if all homes
2 and businesses adopted the most efficient, commercially available *cost-effective*
3 measures” (EPRI Study, Page xiv). This only includes the measures that pass a variation
4 of the Participant test. Economic potential does not address the “rate of market
5 acceptance of those measures” (EPRI Study, Page xiv).

6 Achievable potential “refines economic potential by taking into account various barriers
7 to customer adoption” (EPRI Study, Page xiv). EPRI also splits achievable potential into
8 two categories: Maximum Achievable Potential (“MAP”) and Realistic Achievable
9 Potential (“RAP”). MAP “takes into account those barriers that limit customer
10 participation under a scenario of perfect information and utility programs” in that it
11 “involves incentives that represent 100 percent of the incremental cost of energy
12 efficiency measures above baseline measures” (EPRI Study, Page xiv). RAP “represents
13 a forecast of likely customer behavior” and considers “existing market, financial,
14 political, and regulatory barriers that are likely to limit the amount of savings that might
15 be achieved through energy-efficiency and demand-response programs” (EPRI Study,
16 Page xiv).

17 The Company considers these definitions to be a good point of reference when
18 considering industry accepted definitions.

19 **Q. How does the Company analyze cost-effectiveness?**

20 A. As I explained previously, the Company recommends using the four Tests in determining
21 cost-effective DSM programs on a total portfolio basis pursuant to the Commission’s
22 Cost/Benefit Rules. However, actual results are necessary to confirm that projected

1 reductions are being achieved after programs are actually implemented and customers
2 have actually subscribed to the programs. The Company believes that the proposed and
3 measured results of implemented programs should be compared using standard
4 measurement and verification (“M&V”) analyses to ensure expected results are being
5 achieved. In addition, customer acceptance and assessment of the actual costs associated
6 with achieving confirmed reductions should be evaluated to not only help establish any
7 additional design criteria in implementing or continuing specific programs, but also to aid
8 in determining if the programs will continue to be cost-effective and reliable in
9 comparison to other options available to meet customers’ growing energy needs in the
10 future.

11 **Q. Please discuss the Company’s proposed use of M&V as it relates to achievable cost-**
12 **effectiveness.**

13 A. The Company believes that M&V of DSM programs is an important component of
14 evaluating the actual results of programs compared to the costs to reach a projected level
15 of reductions. The M&V process ensures that DSM programs provide the benefits that
16 were projected as part of the cost/benefit Tests that I mentioned earlier. Specifically, the
17 M&V process supports further development of DSM programs and validates expected
18 reductions by measuring, verifying, tracking, and reporting energy and demand savings,
19 as well as assessing actual cost impacts that result from program implementation.

20 The North American Energy Standards Board (“NAESB”), a voluntary non-profit
21 organization comprised of members from natural gas and electric industries, is in the final
22 stages of developing a common framework of the model business practices for M&V of
23 demand response programs in retail energy markets and has already completed M&V

1 standards for wholesale energy markets. The purpose of these standards is to ensure that
2 regulatory commissions and participants with dispatchable demand response products
3 have access to uniform information that will enable them to report consistent values for
4 M&V of the programs.

5 **Q. Are there other factors that should be considered in determining whether the DSM**
6 **target is “achievable,” “cost-effective” and can be “realistically accomplished?”**

7 A. The Company believes that the cost-benefit Tests are good indicators for determining the
8 cost-effectiveness of the DSM programs, but still believes that other factors must be
9 considered when determining whether a DSM portfolio is in the public interest.
10 Customer acceptance, as mentioned earlier, is another extremely important element in
11 determining whether or not certain goals may be achieved. Not only do customers need
12 to subscribe to the programs, but there is a strong reliance on whether they will be willing
13 to change their behaviors to help produce the reductions that are needed to reach the
14 reduction goals. Commercial and industrial customers have to determine whether their
15 business processes can change to respond to pricing signals that are intended to reduce
16 demand and, again, whether the savings offered by these programs is enough to offset
17 any inconveniences or changes in their business processes. The level of incentives that
18 will entice more customers to participate in these programs may be affected by changes
19 in the economy. More specifically, the most recent economic changes are significant
20 enough that customers who typically would be more willing to receive a payback on an
21 investment over a two-year period may now want a shorter payback period, which may
22 make certain programs more costly.

1 percent in the same period, it is a drastic increase from Virginia's 2007 unemployment
2 rate of just three percent.

3 It has been projected that the economy, both in Virginia and as a nation, will begin
4 recovering by the end of 2009. As a result, the Virginia GSP has been forecasted to grow
5 approximately two percent in 2010, followed by a hefty 4.4 percent rise in 2011. Similar
6 to past recessions, it has been projected that unemployment rates will be slow to recover.

7 The most recent annual load forecast for the Company, shown in my Schedule 1, was
8 developed by the Company in June 2009.

9 **Q. Commission Question No. 6 asks "What is 'the range of consumption and peak load
10 reductions that are potentially achievable by each generating electric utility?'"**

11 **Please comment.**

12 A. The Company believes that setting the 10 Percent Goal against the 2006 base year
13 establishes a realistically accomplishable target that can be met in a cost-effective
14 manner.

15 **Q. Commission Question No. 7 asks "What is 'the range that consumers would pay to
16 achieve those reductions and the range of financial benefits or savings that would be
17 realized if the targets were met over a 15-year period?'" Please comment.**

18 A. The Company believes that many customers view increases or decreases in their bills as
19 an indication of changes in their rates instead of changes in their usage. In other words,
20 while the Company's rates have been capped for many years, customers may have the
21 perception that their rates have increased since they have added new appliances and other
22 devices over time that use energy, so their usage and, hence, their bills have increased.

1 Since the Company has not yet had direct experience in implementing DSM programs to
2 all customers, and there have been no rate adjustments associated with any DSM
3 programs, it is very difficult to determine how customers would perceive savings or have
4 the ability to see costs directly related to the implementation of DSM programs. For
5 example, the bills of non-budget-billing customers fluctuate with changes in weather. A
6 customer participating in a DSM program may not experience a smaller bill from one
7 month to the next because DSM program savings are offset by increased heating or air
8 conditioning. Though the customer may have saved money relative to what he or she
9 would have paid absent participation in the DSM program, the customer may not “see”
10 the savings since that customer still has a higher electric bill relative to the prior month.

11 Other considerations related to cost impacts are whether customers will change their
12 lifestyles long-term in order to achieve the level of reductions projected for DSM
13 programs that may be offered to them. Stated differently, if customers subscribe to a
14 program that requires them to be a little warmer in the summer and a little cooler in the
15 winter, the question is whether they will continue to make those changes in the long run.
16 If they do not, there will be increased costs to them and others related to DSM programs
17 without the benefit of reducing energy or demand.

18 For these reasons, the Company believes that M&V will be even more important to have
19 in place to assess these programs not only to demonstrate the ability of DSM programs to
20 reduce both energy and demand, but also to educate both customers and utilities about the
21 actual costs and direct benefits from these programs. In addition, the fact that the
22 Company and other utilities within Virginia have not yet implemented DSM programs on
23 a broader scale is another reason that the Company believes that the Commission should

1 consider interim targets and reporting progress toward goals to aid in assessing the ability
2 to achieve any longer term targets.

3 SECTION V: DSM TARGET IMPACTS

4 **Q. Commission Question No. 5 asks “What is the potential impact of the generating**
5 **electric utility’s demand-side management program on economic development in**
6 **the Commonwealth?” Does the Company have a position on the relationship**
7 **between energy efficiency and economic development?**

8 A. Yes. Available, reliable, and affordable electricity are important components of the
9 decision making process by businesses when they are deciding to move to or expand
10 operations in Virginia. Large commercial and industrial facilities require significant
11 amounts of electricity to operate. Particularly unique to the Company’s Virginia service
12 territory are its high-tech and internet businesses that require vast amounts of electricity
13 24 hours a day, seven days a week with nearly 50 percent of the world’s internet traffic
14 passing through the Northern Virginia/DC Metro area. While it is difficult to isolate the
15 exact impact of the internet boom on Virginia’s economy, there is little doubt that
16 internet-related businesses, such as server farms, have had – and will continue to have – a
17 strong positive impact on electricity demand in the Company’s service territory. In
18 Northern Virginia alone, there are 36 existing data centers with 14 additional data centers
19 expected by 2012. Cost-effective DSM programs can free up capacity on peak days that
20 will allow for additional economic growth and increased reliability. At the same time, if
21 DSM targets are too aggressive and investments in new generation are not made in a
22 timely manner, then economic development can be hampered because there could be a
23 shortfall of available, reliable and affordable electricity.

1 The Company supports energy conservation that can be achieved in a cost-effective
2 manner, with the resulting decrease in energy requirements during peak and non-peak
3 times, thereby decreasing the overall load. This generally means that energy costs can be
4 mitigated, which results in savings to all customers. Although some large customers may
5 opt-out of the programs, they will still reap the system benefits created from other
6 customers participating. Moreover, some DSM programs allow customers to take their
7 load off the system and receive payment for that off-set. Therefore, besides lower overall
8 energy bills, certain businesses have the opportunity to make their back-up generation a
9 source of revenue.

10 State law recognizes that cost-effective DSM programs, along with supply-side options,
11 will play a major role in the continued provision of affordable and reliable electric service
12 to Virginia customers. In fact, utilities are required by law to consider demand-side
13 options in developing their integrated resource plans for meeting customer needs. The
14 Company agrees with this view and believes that cost-effective DSM programs can give
15 utilities an important additional tool in meeting customer needs in a reliable, affordable,
16 and efficient manner. A proper balance of cost-effective demand-side and supply-side
17 options will help ensure that these goals are met and promote the continued economic
18 development of the Commonwealth. The Company believes it is important that its
19 portfolio of programs remains cost-effective to ensure that rates do not increase
20 significantly, which could, in turn, hurt economic development.

21 **Q. Commission Question No. 8 asks “How should the Commission ‘determine a just**
22 **and reasonable ratemaking methodology to be employed to quantify the cost**

1 **responsibility of each customer class to pay for generating electric utility-**
2 **administered demand-side management programs?'"**

3 A. Assignment of DSM program costs to the participating jurisdiction is appropriate since:
4 1) the programs are approved on a jurisdictional basis, 2) customers will be making
5 decisions to participate in such programs, 3) demand and energy reductions due to these
6 programs will impact determination of allocation factors for the jurisdiction, and 4) the
7 Company will know most of the DSM program costs by premise, excluding its proposed
8 Voltage Conservation Program and certain common costs associated with program
9 implementation and administration. The reductions to energy usage and demand caused
10 by DSM programs will affect the jurisdictional allocation factors. It would be unfair to
11 allocate costs of these programs across the system because certain jurisdictions are not
12 eligible to participate in the programs and should not bear cost responsibility because of
13 the participation of another jurisdiction's customers. Assignment places the cost
14 responsibility with the jurisdiction in which customers achieve demand and energy
15 reductions. Then allocation to the classes based on an appropriate factor determines the
16 costs of the programs according to relative usage and/or demand of the customer classes.
17 With an exempt provision in the current statute, § 56-586.1 A 5, it is even more
18 appropriate to allocate to the classes. Finally, assigning costs to the jurisdiction and then
19 allocating to the customer classes is consistent with the methodology used for load
20 management programs conducted by the Company in the 1980s and 1990s.

21 **Q. Are there other ratemaking issues to consider?**

22 A. Yes. The General Assembly recently enacted House Bill 2506 (Chapter 824 of the 2009
23 Acts of the Assembly) which provides cost compensation and margins for utilities to

1 implement energy efficiency programs. In addition, this legislation recognizes that
2 utilities should have an opportunity to recover revenue reductions as a result of energy
3 efficiency programs. This may be a factor in establishing a DSM target.

4 **Q. Commission Question No. 9 asks “What ‘class cost responsibility methods [are] used**
5 **in other jurisdictions,’ and ‘would [it] be in the public interest for the**
6 **Commonwealth to have a similar policy’ to other jurisdictions that permit certain**
7 **customers to be exempt from participating in and/or paying for a utility’s demand-**
8 **side management programs?”**

9 A. As noted above, the 2009 General Assembly passed House Bill 2506, which addressed
10 class cost responsibility under Section 56-585.1 A 5 c. It defines criteria for certain
11 customers to be exempt from participating in and/or paying for energy efficiency
12 programs. House Bill 2506 includes a provision allowing large general service customers
13 using more than 500 kW of demand from a single meter of delivery to opt out of DSM
14 programs. Additionally, no costs related to DSM programs may be assigned to any
15 customer having a verifiable history of more than 10 MW of demand from a single meter
16 of delivery. The Commission is to promulgate rules and regulations to determine
17 standards for such customers that file for such an exemption from DSM programs no later
18 than November 15, 2009. It is prudent that these rules provide adequate criteria to insure
19 energy efficient programs implemented by these customers are appropriately measured
20 and verified per established industry standards. Given that the General Assembly has
21 enacted this language in the statute, the question regarding exempt and/or opt-out
22 customers has already been defined.

1 In North Carolina, Section 62-133.9 (f) of the General Statutes states, “None of the costs
2 of new demand-side management or energy efficiency measures of an electric power
3 supplier shall be assigned to any industrial customer that notifies the industrial
4 customer’s electric power supplier that, at the industrial customer’s own expense, the
5 industrial customer has implemented at any time in the past or, in accordance with stated,
6 quantified goals for demand-side management and energy efficiency, will implement
7 alternative demand-side management and energy efficiency measures and that the
8 industrial customer elects not to participate in demand-side management or energy
9 efficiency measures under this section.”

10 **Q. Does this conclude your testimony?**

11 **A. Yes, it does.**

BACKGROUND AND QUALIFICATIONS
OF
SHANNON L. VENABLE

I graduated from Michigan State University in June of 1982 with a Bachelor of Science Degree in Electrical Engineering and a minor in Biomedical Engineering. I am a member of the Society of Women Engineers, United Way's Women's Leadership Council, and the Eta Kappa Nu Society. Additionally, I became the Vice Chairman of the South Eastern Electric Exchange ("SEE") IRP Task team in 2009 and served as Secretary in 2008.

I joined Virginia Electric and Power Company in July of 1982 as an engineer in Transmission and Distribution Construction and Operations. I have held various management positions in Metering and Energy Services supporting End Use Studies and Measurement & Verifications of DSM programs, Energy Information and Telecommunications, and Energy Efficiency before being promoted to Director of IT Telecommunications in 1998. From 1999 to 2007, I held director-level leadership positions in Customer Services, Business Excellence, Electric Transmission, IT Enterprise Services, and other strategy-based assignments. Additionally, I was one of the initial deployment champions for Six Sigma at Virginia Electric and Power Company and am a certified Master Black Belt in Six Sigma. I am currently Vice President of Integrated Resource Planning in the Regulation and Integrated Planning organization of Virginia Electric and Power Company. I am responsible for the development of corporate-level initiatives that integrate capacity plans, transmission plans, and conservation and load management in support of the Company's regulatory initiatives.

In January of 1996, I gave a presentation on Strategic Partnering to Enable Energy Management and Customer Information Capabilities at the Utility Information Technology, System Strategies, and Customer Satisfaction Symposium. In 1992, I was on the Edison Electric Institute's ("EEI") editorial team for the 1992 publication of the Handbook for Electricity Metering and was the Company's representative to EEI's Metering Subcommittee from 1992 to 1994.

VIRGINIA ELECTRIC & POWER COMPANY

SUMMARY OF ENERGY SALES & PEAK LOAD FORECAST

	2009	2024	Compound Annual Growth Rate (%) 2009- 2024
DOMINION LSE			
TOTAL ENERGY SALES	79,333	113,041	2.39%
RESIDENTIAL	29,851	38,408	1.69%
COMMERCIAL	27,739	47,999	3.72%
INDUSTRIAL	9,306	10,741	0.96%
RESALE	1,883	2,533	2.00%
PUBLIC AUTHORITY	10,267	13,002	1.59%
STREET AND TRAFFIC LIGHTING	287	358	1.48%
SEASONAL PEAK (MW)			
Summer	16,368	22,544	2.16%
Winter	14,288	18,992	1.92%
DOMINION ZONE			
SEASONAL PEAK (MW)			
Summer	18,727	25,618	2.11%
Winter	16,481	21,609	1.82%
ENERGY OUTPUT (GWH)	93,368	131,821	2.33%

Note: The sales and peaks have not been reduced for the impacts of DSM.

INPUT ASSUMPTIONS TO THE ENERGY SALES & PEAK DEMAND MODEL

	2009	2024	Compound Annual Growth Rate (%) 2009- 2024
DEMOGRAPHIC:			
Customers (000)			
Residential	2,140	2,615	1.35%
Commercial	233	281	1.26%
Population (000)	7,849	8,963	0.89%
Housing - Total Starts	18,604	53,620	na
ECONOMIC:			
Employment (000)			
Manufacturing	241	243	0.06%
Government	699	743	0.41%
Income (\$)			
Per Capita Real disposable	31,340	42,001	1.97%
Price Index			
Consumer Price (2000=100)	211	294	2.24%
VA Gross State Product (GSP)	312	500	3.20%



HUNTON & WILLIAMS LLP
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

RICHARD D. GARY
DIRECT DIAL: 804-788-8330
EMAIL: rgary@hunton.com

FILE NO: 21054.159

June 30, 2009

By Hand

Hon. Joel H. Peck
Clerk
State Corporation Commission
Document Control Center
Tyler Building, 1st Floor
1300 East Main Street
Richmond, Virginia 23219

Commonwealth of Virginia
At the Relation of the
State Corporation Commission
Ex Parte: In the Matter of Determining
Achievable, Cost-effective Energy Conservation and
Demand Response Targets, etc.
Case No. PUE-2009-00023

Dear Mr. Peck:

Enclosed on behalf of Appalachian Power Company are Comments and Testimony in Case No. PUE-2009-00023.

Sincerely,

Richard D. Gary

RDG/tms
Enclosures



Hon. Joel H. Peck
June 30, 2009
Page 2

cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Kendrick R. Riggs, Esq.
Pamela J. Walker, Esq.
James R. Bacha, Esq.
Charles E. Bayless, Esq.
Noelle C. Coates, Esq.

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

COMMONWEALTH OF VIRGINIA,

At the relation of the

STATE CORPORATION COMMISSION

CASE NO. PUE-2009-00023

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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly.

**COMMENTS AND TESTIMONY OF
APPALACHIAN POWER COMPANY**

VOLUME 1 OF 4
FILED: JUNE 30, 2009
PUBLIC VERSION

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

**COMMENTS AND TESTIMONY OF
APPALACHIAN POWER COMPANY
CASE NO. PUE-2009-00023**

INDEX

- **COMMENTS**

- **DIRECT TESTIMONY AND EXHIBITS**
 - **BARRY L. THOMAS**
 - **FRED D. NICHOLS II**
 - **WILLIAM K. CASTLE**

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

COMMONWEALTH OF VIRGINIA,

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CASE NO. PUE-2009-00023

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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly.

COMMENTS OF APPALACHIAN POWER COMPANY

In its 2009 Session, the Virginia General Assembly enacted legislation that directs the State Corporation Commission (the “Commission”) to conduct a formal evidentiary hearing to determine the achievable, cost-effective energy conservation and demand response targets that can realistically be accomplished in the Commonwealth through demand-side management (“DSM”) portfolios administered by electric utilities.¹ On April 30, 2009, in accordance with this legislative directive, the Commission issued an Order Establishing Proceeding and Setting Evidentiary Hearing (the “Order”). The Order named each “generating electric utility” in the Commonwealth, including Appalachian Power Company (“APCo” or the “Company”), as a respondent, and required the respondents to file testimony and legal briefs addressing a number of Questions regarding energy conservation and demand response implementation in the Commonwealth.

¹ Chapter 855 and Chapter 752 of the 2009 Acts of Assembly (the “DSM Bills”).

The Company welcomes the opportunity to assist the Commission's analysis of these important topics, and is confident that through this proceeding, the Commission can arrive at fair and reasonable regulations that will enable the implementation of cost-effective DSM programs. The Company believes that the implementation of DSM targets in Virginia can and should be done through a careful, thorough consideration of all possibilities, practicalities and impediments. This proceeding provides the ideal forum for such consideration.

The Company will stress several points in its presentation, particularly that it is of utmost importance that a solid regulatory foundation must be developed and an individualized assessment of each utility's potential for DSM implementation made before a specific target is imposed on any of the respondent utilities. Moreover, if a specific target is deemed necessary, the Company recommends that the targets be short-term to account for rapidly evolving technology, as well as to account for economic uncertainties. It is essential that any target be based on a known historical value, and should be expressed in ranges, affording flexibility for the utility and protecting the customers from risky investments. Lastly, the Company stresses the importance of a periodic assessment, and if warranted, a periodic recalibration of any DSM goal or target, so to align a utility's efforts with prevailing conditions.

In support of its position, and to assist the Commission's analysis, APCo offers the testimonies of the following witnesses:

1. Mr. Barry Thomas, APCo's Director of Regulatory Services, Virginia and Tennessee, provides an overview of the Company's filing in this proceeding, and will suggest a set of guiding principles for the Commission. Mr. Thomas addresses Questions No. 3, 8 & 9.
2. Mr. Fred D. Nichols II, Manager of Consumer Programs for American Electric Power Service Corporation. Mr. Nichols reviews a number of practical issues related to implementation of DSM programs for the Company in its Virginia service territory, and discusses the development and nature of a market potential study, discussed below.

3. Mr. William Castle, Director of Demand Side Management and Resource Planning. Mr. Castle provides a more detailed review of the Company's analysis and evaluation of DSM options, and discusses the use of the various cost-effectiveness tests, recommending that the Total Resource Costs Test ("TRC Test") be adopted as the primary screening test for evaluating the cost-effectiveness of DSM in Virginia. Mr. Castle addresses Commission Questions 1, 2, 5, 6 & 7.

In addition, the Company attaches to these Comments a market potential study that was conducted on its behalf by Summit Blue, LLC to assess the relative potential of various DSM programs to produce various energy and/or peak demand reductions in APCo's Virginia service territory.²

Additional Response to the Commission's Questions

The Company wishes to provide an additional response to Questions No. 2 and 4³ regarding the Commission's selection of a test with which to measure the cost-effectiveness of a DSM program, and the Commission's consideration of the public interest when selecting such test.

The Company believes that, consistent with longstanding Commission practice, the Commission's consideration of "public interest" should encompass those factors within its jurisdiction, such as the rates charged by the Commonwealth's electric utilities and the adequacy and reliability of the service received by the Commonwealth's customers. The public interest is not served, for example, if the introduction and implementation of DSM programs results in rates

² The market potential study is attached to these Comments as Company Attachment A (the DSM Action Plan), Company Attachment B (the DSM Potential Study) and Company Attachment C (DSM Action Plan and DSM Potential Study Appendices).

³ Order at 4: "What industry-recognized tests should be used in determining cost-effective consumption and peak load reductions and what relative weighting should be afforded to any test for use by the respondent generating electric utility?" and "How should the Commission determine the "public interest" in preparing a cost-benefit analysis of a demand-side management program?"

that are not just and reasonable. Nor is the public interest served if the introduction and implementation of DSM programs impairs the electric utility's ability to provide reliable and adequate service to its customers.

The Company notes that, although its powers over the respondent utilities are broad, the Commission can only act within the boundaries of the powers delegated to it by the General Assembly and as established by the Virginia Constitution. As the Commission has previously determined, consideration of the public interest in adopting a cost-effectiveness test must be limited to the areas over which the Commission does have explicit grants of jurisdiction.⁴ As the General Assembly has not granted the Commission the explicit statutory authority to consider, for instance, environmental externalities, it would be impermissible for the Commission to use that as a criterion for selecting a cost-benefit test.

Accordingly, the Commission should not implement the use of the Societal Test to determine the cost-effectiveness of DSM programs, for the Societal Test incorporates a definition of "public interest" that goes well beyond that which the Commission is empowered to consider. Moreover, externalities that might be advocated to be considered as part of the Societal Test are impossible to quantify objectively, or effectively. As Company witness Castle discusses in more detail in his testimony, the Company recommends that the Commission adopt

⁴ See, e.g. *In re. Investigation of Conservation and Load Management Programs*, Order Issuing Rules on Cost/Benefit Measures, Case No. PUE-1990-00070 (June 28, 1993). Similarly, as noted by the Staff in its *Report to the State Corporation Commission in preparation for the Commission's Report to the Governor and the General Assembly*, the "Commission has previously ruled that it did not have the statutory authority to consider" the external effects of programs on health, safety, local economy and the environment, that are measured by the Societal Cost Test. *Staff's Report to the State Corporation Commission in preparation for the Commission's Report to the Governor and the General Assembly as required by the Third Enactment Clause of SB 1416*, (Nov. 16, 2007) at 72.

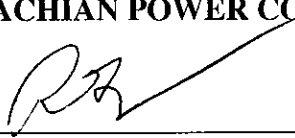
the TRC Test as the primary measure through which to gauge the cost-effectiveness of any DSM programs.

APCo will be pleased to discuss these issues in the Commission's hearing now scheduled for September 23, 2009.

Respectfully submitted,

APPALACHIAN POWER COMPANY

June 30, 2009

By: 
Counsel

James R. Bacha (VSB # 74536)
Charles E. Bayless (VSB # 74537)
AMERICAN ELECTRIC POWER SERVICE CORPORATION
1 Riverside Plaza
Columbus, Ohio 43215
Phone: (614) 716-1615
Fax: (614) 716-1687

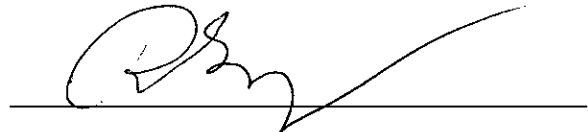
Richard D. Gary (VSB # 14155)
Noelle J. Coates (VSB # 73578)
HUNTON & WILLIAMS LLP
Riverfront Plaza, East Tower
951 East Byrd Street
Richmond, Virginia 23219-4074
Phone: (804) 788-8200
Fax: (804) 788-8218
rgary@hunton.com
ncoates@hunton.com

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of June, 2009, a true copy of the foregoing Comments of Appalachian Power Company was delivered by hand or mailed, first-class, postage prepaid, to the following:

William H. Chambliss, Esq.
Office of General Counsel
State Corporation Commission
Tyler Building, 10th Floor
1300 E. Main Street
Richmond, Virginia 23219

C. Meade Browder, Jr., Esq.
Division of Consumer Counsel
Office of Attorney General
900 E. Main Street, 2nd Floor
Richmond, Virginia 23219



1 [DSM] portfolios administered by” APCo in its Virginia service territory. I will also note
2 certain regulatory and/or statutory steps that must precede the implementation of any
3 specific demand reduction or energy efficiency target by the Commonwealth’s utilities. I
4 also provide responses to Questions No. 3, 8 & 9 posed by the Commission in its April
5 20, 2009 Order Establishing Proceeding and Setting Evidentiary Record in Case No.
6 PUE-2009-00023 (the Order).

7 **Q. WHAT IS THE BASIS FOR THIS PROCEEDING?**

8 A. In the 2009 legislative session, the General Assembly asked the Commission to provide
9 direction and information on appropriate policies to follow in Virginia for the
10 development of cost-effective DSM measures through a report to the General Assembly
11 and the Governor, due on November 25, 2009. In the proceeding initiated by the Order,
12 the Commission sought input from a broad range of persons and organizations having an
13 interest in energy conservation in Virginia and posed several questions to the respondent
14 electric utilities and other interested parties.

15 **Q. WOULD YOU PLEASE ELABORATE ON WHAT YOU MEAN BY ENERGY**
16 **EFFICIENCY PROGRAMS, DEMAND RESPONSE AND DEMAND SIDE**
17 **MANAGEMENT PORTFOLIOS?**

18 A. Yes. The Code of Virginia contains specific definitions for both Energy Efficiency (EE)¹
19 programs and Demand Response (DR)² programs. We adopt these definitions. With

¹ **Energy efficiency program** “means a program that reduces the total amount of electricity that is required for the same process or activity implemented after the expiration of capped rates. Energy efficiency programs include equipment, physical, or program change designed to produce measured and verified reductions in the amount of electricity required to perform the same function and produce the same or a similar outcome.” Chapter 924 of the 2009 Acts of Assembly (House Bill 2506).

² **Demand response** “means measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.” Chapter 924 of the 2009 Acts of Assembly (House Bill 2506).

1 respect to Demand Side Management (DSM) Portfolios, it is the Company's position that
2 both EE and DR programs are included in and can be a part of a DSM portfolio options.

3 **Q. WOULD YOU PLEASE OUTLINE THE COMPANY'S POLICY WITH**
4 **RESPECT TO THIS PROCEEDING?**

5 A. The Company believes that electric utilities should consider for implementation only
6 those DSM programs that are reasonably predicted to be cost-effective in terms of their
7 overall impact on costs, as compared to the cost of traditional supply options. Thus, the
8 fundamental regulatory underpinnings of DSM implementation and analysis must be
9 established before any specific target is identified and before any broadly-applicable
10 group or individual programs are implemented.

11 The Company has undertaken, and presents in its Comments filed in this
12 proceeding, the necessary first step for its own DSM planning process: a market potential
13 study (the Study) that was conducted on its behalf by Summit Blue Consulting, LLC
14 (Summit Blue) to assess the relative potential of various DSM programs to produce
15 various energy and/or peak demand reductions in Virginia. The Company has recognized
16 for some time that its and the Commonwealth's EE/DR programs, targets or plans should
17 only be implemented after careful analysis. As a result, it undertook this study using an
18 independent and experienced third-party service provider, Summit Blue.

19 While the Study indicates that a range of outcomes in terms of reduced energy
20 and demand consumption (savings) is possible, the Company supports a DSM program
21 that will result in a realistic level of savings within an initial 5-year program period (the
22 period the Company recommends as an appropriate focus at this stage of development of
23 DSM in Virginia) and believes that is a savings of approximately 2% of APCo's 2008

1 Virginia energy consumption and approximately 5% of its 2008 peak load. The Study
2 suggests that the costs of this more realistically accomplishable level of savings is in the
3 range of \$80-\$100 million for direct program and administrative costs and that, in order
4 to achieve higher levels of savings, customers will have to bear more risks and pay higher
5 costs over a longer period of time. The Study is addressed in greater depth by Company
6 witnesses Nichols and Castle and is offered for use in assessing that which is practical for
7 the Company.

8 **Q. PLEASE OUTLINE THE RESPONSIBILITIES OF THE COMPANY'S OTHER**
9 **WITNESSES.**

10 A. In addition to my testimony, the Company will present the testimony of two other
11 witnesses, as described below.

12 Mr. Fred D. Nichols II will discuss the development and nature of the Study and
13 will review certain assumptions and guidance given to Summit Blue. He will also review
14 a number of practical issues related to implementation of DSM programs for the
15 Company in its Virginia service territory.

16 Mr. William K. Castle will provide a more detailed review of the Company's
17 analysis and evaluation of DSM options. He will discuss the use of the various cost-
18 effectiveness tests and will recommend that the Total Resource Costs Test, or TRC Test,
19 be adopted as the primary screening test for evaluating the cost-effectiveness of DSM in
20 Virginia. He will review the Study results and will address Commission Questions 1, 2,
21 5, 6 & 7.

22 **Q. WHAT COMMENT DOES THE COMPANY OFFER WITH RESPECT TO THE**
23 **THREE DEFINITIONS ("ACHIEVABLE," "COST EFFECTIVE" AND "BE**

1 **REALISTICALLY ACCOMPLISHED”), AS SET FORTH IN QUESTION 3 IN**
2 **THE COMMISSION’S PROCEDURAL ORDER, AND HOW DO YOU SUGGEST**
3 **THAT THE THREE CONCEPTS BE APPLIED BY THE COMMISSION?**

4 A. The Company believes that these definitions, as will be ultimately applied by the
5 Commission, are critical to the development of DSM policies and rules in Virginia.
6 Thus, the Company suggests the following definitional framework for these three terms:

7 1. **Achievable** may be the broadest concept of the three measures of potential DSM
8 programs. Different aspect of “potential” are often discussed as a definition for
9 “achievable,” such as technical feasibility or economic viability. I consider
10 “achievable” DSM to be a range of values of energy efficiency and peak demand
11 reductions that are possible through utility programs for a specified time period.
12 Given the extent of existing technology and resource availability. This definition
13 of “achievable” therefore recognizes that there will always be very real
14 constraining factors on any DSM program. Moreover, given many of the
15 uncertainties in this evolving area, the Company suggests that the concept of
16 “achievable,” as applied to any particular DSM outcome, is best expressed, for
17 planning purposes, in terms of a range. Specific targets are very rarely achievable
18 in any arena, especially one that is as evolving and uncertain as DSM.

19 2. A program or measure should be found to be *cost-effective* if the present value of
20 the incremental costs associated with the program is less than the present value of
21 providing the electric energy and capacity needed to support the consumption that
22 could be avoided. The Company recognizes that different perspectives on the
23 concept of cost-effective may be presented in this proceeding by different

1 stakeholders. Company Witness Castle will discuss this matter in more detail in
2 his testimony.

3 3. ***Be realistically accomplished***, the most important term and definition, signifies
4 that there are a number of factors that must be evaluated with each possible
5 program, in addition to the more technical, quantitative or engineering aspects
6 related to the two previous terms. These factors would include, but would not
7 necessarily be limited to, the following:

- 8 • Cost and impacts on the cost of electricity to the Company and to both
9 program participants and non-participants;
- 10 • Timeline factors;
- 11 • Implementation resources, such as availability, cost and related market
12 factors, and technological changes;
- 13 • Need for flexibility and adaptability; and
- 14 • Customer behavior and acceptance

15 **Q. DOES THE COMPANY HAVE ANY SUGGESTIONS REGARDING THE**
16 **COMMISSION'S ANALYSIS OF DSM THAT CAN BE REALISTICALLY**
17 **ACCOMPLISHED IN VIRGINIA?**

18 A. Yes. In the early stages of the development of the Commonwealth's DSM policies and
19 rules, we suggest that the Commission adopt the following set of guiding principles:

- 20 1. **Cost-effectiveness is paramount.** Any DSM program must be determined to be cost-
21 effective pursuant to the application of the TRC Test, which is the most balanced and
22 reasonable cost-effectiveness test.

- 1 2. **The utility is not omnipotent.** Electric utilities can only affect certain aspects of its
2 customers' consumption and should not be expected or required to undertake actions of
3 programs that are outside of its direct pricing or customer/supplier relationship.
- 4 3. **A strong and clear regulatory and statutory foundation is essential.** The imposition
5 of specific quantitative goals or targets (outcomes), if such precision is determined to be
6 necessary, must be preceded by the development of clear regulatory rules, protocols and
7 guidelines, including those relating to cost recovery and application of opt-out provisions.
8 The utility and its customers must be protected from mandated expenditures with
9 uncertain future benefits, and it is the Commission's obligation to provide such
10 protection.
- 11 4. **Targets should be based upon a comparison to actual, known historical**
12 **consumption or load values for the utility.** To state savings outcomes in terms of a
13 projected value of consumption unduly complicates the process of review and assessment
14 by adding an unnecessary element of unpredictability.
- 15 5. **The interests of all customers must be protected and balanced.** The utility should not
16 be required to forsake or ignore its statutory obligations to provide adequate service at
17 just and reasonable rates: the rate or cost impacts on all customers, both participants and
18 non-participants, must be reasonable over the life of the program, and the implementation
19 of a program must not negatively affect reliability of service.
- 20 6. **Regulatory policies and practices must provide flexibility.** Because the utility is not
21 omnipotent, the Commission should not establish parameters for DSM, such as a timeline
22 or results to be achieved, that are unrealistic or unreasonable in the context of existing
23 technology, the evolution of energy standards, and the likelihood of future technology.

1 The program timeline and any targets should be subject to periodic review and revisions,
2 as may be necessary.

3 **Q. IS UNIFORM APPLICATION OF THESE PRINCIPLES ACROSS ALL**
4 **ELECTRIC UTILITIES IN THE COMMONWEALTH POSSIBLE?**

5 A. I believe that these principles can be generally applied to all utilities, however, each
6 utility's DSM policies, strategies and proposals must be assessed individually, and any
7 resulting goal should be applicable only to that utility. This is the essence of
8 practicability. The Commission's determination should focus on what is realistically
9 accomplishable for the individual utility, given an assessment of a number of relevant
10 factors, such as the utility's mix of customers, the current market supply conditions,
11 historical and expected future investments in power supply, the utility's infrastructure,
12 the utility's ability to implement DSM programs, and the cost and impacts of such
13 implementation.

14 **Q. DOES THE COMPANY HAVE SPECIFIC PLANS FOR IMPLEMENTATION**
15 **OF DSM PROGRAMS IN VIRGINIA?**

16 A. At the present time, and as explained in more detail in Company witness Nichols'
17 testimony, the Company is assessing the results of the Study and will consider the
18 development of regulatory and legislative policies to determine the appropriateness of
19 implementing various programs in Virginia. The Company requires clarity from the
20 Commission before it commits to formal action or a DSM implementation plan -- a
21 clarity that is in the best interests of its customers, the Commonwealth and the Company
22 itself. Once the policy and process aspects of the regulatory treatment and requirements

1 for DSM in Virginia are established, the Company will finalize the precise portfolio of
2 the most cost-effective programs and measures for its customers.

3 However, for purposes of this proceeding and future planning, based upon the
4 Study, the Company believes that a realistically accomplishable targeted savings outcome
5 within an initial 5 year implementation period is approximately 2 % for energy and 5 %
6 for peak demand based on 2008 consumption levels for the Company's Virginia service
7 territory, subject to the opt-out issues discussed below. This is explained in greater depth
8 in the testimony of Company witness Castle.

9 **Q. SHOULD THE COMMISSION ESTABLISH SPECIFIC TARGETS FOR EACH**
10 **OF THE RESPONDENT UTILITIES?**

11 A. The Company strongly recommends against the imposition of any specific target for
12 Virginia's utilities at this time in this proceeding. As I discuss above, the Commission
13 should establish individual targets for each utility but should do so only after the
14 foundations of regulatory policy for DSM have been established. Further, any precise
15 goal would be more properly reviewed in an appropriate time frame concurrently with
16 review of that utility's Integrated Resource Plan (IRP), a process which has not yet
17 occurred.

18 **Q. PLEASE DISCUSS THE EFFECTS ON THIS PROCESS OF THE STATUTORY**
19 **OPT-OUT PROVISIONS FOR CERTAIN LARGER GENERAL SERVICE**
20 **CUSTOMERS.**

21 A. The statutory opt-out policies in Virginia whereby certain larger customers do not
22 participate in the Company's DSM program and the regulatory procedures for
23 implementation of those policies will affect substantially the quantification of any DSM

1 targeted outcomes for the utility, as well as the quantification of recovery and customer
2 impacts.

3 For example, the current statutory opt-out provisions for large industrial
4 customers³ removes a relatively large portion of APCo's retail Virginia energy sales from
5 consideration in establishing programs and energy savings goals. Those provisions
6 provide an automatic elimination from participation or payment for DSM programs for
7 any large customer with a verifiable demand of more than 10 MW. A second opt-out
8 provision for customers with demands of between 500 kW up to 10 MW is possible,
9 subject to regulations that have not been determined by the Commission. The statute
10 requires that these conditions and rules be determined by the Commission by November
11 15, 2009.

12 For the Company, the automatic exemption would apply to approximately 20 of
13 our largest customers which, based upon a period of 12 months ended May 2009,
14 consume about 2.2 billion kWh annually and provide approximately \$107 million in
15 annual revenue. This is about 14 % of the Virginia total retail jurisdictional kWh
16 consumption and about 10% of annual revenue for that same period.

17 The second, or conditional, exemption for customers with loads of 500 kW to 10
18 MW would potentially apply to approximately 390 of the Company's customers
19 consuming over 3.3 Billion kWh and providing over \$190 million in annual revenue, or
20 about 22 % of Virginia total retail jurisdiction kWhs consumption and 17 % of annual
21 revenue.

22 Together, these two exemption or op-out groups comprise over 36 % of
23 jurisdictional energy sales and over 27 % of annual revenue.

³ Chapter 824 (House Bill 2506) of the 2009 Acts of Assembly.

1 **Q. HOW WOULD THE OPT-OUT PROVISION AFFECT THE DETERMINATION**
2 **OF A DSM GOAL OR TARGET FOR APCO ?**

3 A. The opt-out provision obviously reduces both the population of customers to which
4 programs can be applied and the customers and revenue over which recovery would
5 occur. As a result, opt-out provisions must be taken into consideration when determining
6 any planning goal, target or intended outcome. In essence, any goal or target should only
7 be stated in terms of the potential impact on that customer group to which the programs
8 would be applicable. The risk is that a broad statewide standard, such as a percentage
9 reduction in consumption, that is based upon the consumption of all customers, including
10 those who are permitted to opt out, would place an inappropriate burden of savings and
11 recovery on those fewer customers who are not permitted to opt-out of participation or
12 payment.

13 Importantly, the Summit Blue study has not taken into consideration any effects
14 of opt out or exemption from participation. Therefore, its results and any goal or target
15 based upon it must be further refined to consider the statutory opt-out provisions and the
16 future development of Commission rules and requirements for approval of exemption or
17 opt out applications by Customers. The Company's conclusion that the most practical
18 target is one that is closer to the Low Case presented in the Study is based in part on the
19 recognition that the opt-out provisions exist and are not yet fully determinable.

20 **Q. CAN YOU OFFER ANY COMMENT, AS POSED IN QUESTION 9 OF THE**
21 **ORDER, REGARDING THE APPROACHES TAKEN IN OTHER STATES**
22 **WITH RESPECT TO DSM EXEMPTION OR OPT-OUT PROVISIONS?**

1 A. Yes, I have attached as Exhibit BLT-1 a table showing some of the characteristics of
2 both Opt-Out and recovery features of DSM programs for AEP's affiliated Companies.

3 **Q. PLEASE COMMENT ON QUESTIONS 8 AND 9 IN THE ORDER RELATING**
4 **TO RATEMAKING METHODOLOGIES AND CLASS RESPONSIBILITY**
5 **METHODS.**

6 A. The Company has followed a long-standing general ratemaking principle that costs
7 should be recovered from the customer group that causes the cost to be incurred. See the
8 "General Class Cost Responsibility Methods Applied" category of Exhibit BLT-1 for the
9 current treatment used by APCo's AEP System Affiliate companies. Following that
10 concept, any rate design or customer class cost recovery approaches would, to a large
11 degree, be a function of the factors previously discussed with respect to eventual program
12 selection and treatment of opt-out or exemptions. Therefore, it is difficult to provide an
13 answer that would precisely address by what method and from whom recovery should
14 occur, as there are a number of issues yet undecided, many of which will potentially have
15 an outcome based on this docket and future dockets. In general terms, the DSM program
16 costs that are related to capacity or demand should be recovered in the manner as other
17 demand-related costs are recovered in each rate schedule. Thus, depending on the rate
18 schedule DSM program costs could be included in demand charges, in energy charges, or
19 split between the demand and energy charges. As every rate schedule contains an energy
20 charge component, any portion of DSM program costs that can be determined to be
21 related to energy consumption should be recovered from the energy billing units of a
22 tariff.

1 With regards to the determination of which DSM costs are demand-related and
2 which are energy-related , the Company suggests that those costs related to programs that
3 have more of a capacity related impact, such as demand response or demand control
4 programs, should be considered demand related and those programs that seek to improve
5 energy efficiency should be considered energy-related. Although energy efficiency
6 programs will impact customer demand and utility peak loads, and demand response
7 programs will result in some change in energy consumption, an approach that focuses on
8 the predominant effect of each DSM program is recommended as the overall best way to
9 assign DSM program costs to the demand and energy-related cost classifications.

10 **Q. DOES THAT COMPLETE YOUR TESTIMONY?**

11 **A. Yes.**

		Energy Efficiency Opt-Out and Recovery Information APCO Affiliates									
		Arkansas	Indiana	Kentucky	Michigan	Ohio	Oklahoma	Tennessee	Texas	Louisiana	West Virginia
		No	No	Yes	Yes	Yes	Yes	No	Yes	No	No
General											
Opt-Out Provision											
Primary Regulatory and Legislative Guidance Reference		Arkansas Code Ann. Sec. 23-3-401 to 405 / Docket 06-004-R	170 IAC 4-8-1 through 4-8-8	Revised Code sec. 275-285(3)	SB 213, Section 93(1)	Proposed ORC Section- 4901.1-39-05 under Recovery Rulmaking, Docket 08-888-EL-ORD	Oklahoma Code 165.35-41-4(b) (11)		HB 3693		
General Information		Code-Statutory energy efficiency provisions. Docket-Rules for Conservation and Energy Efficiency Programs	Does not have energy efficiency opt-out provision.	Commission assigns the cost of DSM programs only to the class or classes of customers which benefit from the program. Industrial customers are not assigned the cost of utility DSM programs.	Allows for an eligible primary or secondary electric customer to be exempt from EE charges if the customer filed with its electric provider and implements a self-directed energy optimization plan.	Mercantile customers who commit their peak demand reduction, or energy efficiency programs for integration with the electric utility's programs may apply for an exemption.	Any high volume electricity user may opt out of some or all energy efficiency programs by submitting a notice to the Director of the Public Utility Division and to the electric utility that submits the demand portfolio.	Tennessee considering legislation dealing with TRA authority over DSM from energy efficiency provisions and from paying into the EE rider.	Industrials that are 69 kV or above are exempt from energy efficiency programs and from paying into the EE rider.		
Detail			Provides for Demand Side Cost recovery	Individual industrial customers with energy intensive processes may be allowed to implement cost-effective energy efficiency measures in lieu of a utility's approved DSM program if the alternative measures are not subsidized by other customer classes.	The customer must have had an annual peak demand in the preceding year of at least 2 MW at each site to be covered by the self-directed plan or 10 MW in the aggregate at all sites to be covered by the plan.	Ohio has allowed for self-directed programs. Mercantile customers and a utility may agree to include energy efficiency savings or peak demand reductions accomplished by the mercantile customer within the utility's portfolio plan.					
General Class Cost Responsibility Methods Applied		Recovery is from all customers (or classes) using a blended demand energy allocator.	Recovery assigned to the (R.C.) sector. (All existing programs are currently residential). Generally assigned by kWh (energy) (energy).	Recovery assigned at the (R.C.) sector based on weighting average sector relative to total revenues. (Residential recovery assigned by kWh (energy), C & I recovery as customer charge).	Recovery assigned to class (or classes) of customers that may benefit from the program(s). Generally assigned by kWh (energy).	Recovery assigned to class (or classes) of customers that may benefit from the program(s). Generally assigned by kWh (energy).	Recovery assigned to class using a demand energy allocator. The recovery is then assigned by kWh(energy basis). Recovery may be redistributed relative to opt-out provisions.		Recovery assigned to class (or classes) of customers that may benefit from the program(s). Generally assigned by kWh (energy).		

* Data provided as of 06/2009 and subject to change
* Information provided for Jurisdictions of APCo affiliates

**DIRECT TESTIMONY OF
FRED D. NICHOLS II
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUE-2009-00023**

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.**

2 A. My name is Fred D. Nichols II and my business address is 1 Riverside Plaza, Columbus, Ohio
3 43215. I am currently Manager – Consumer Programs for American Electric Power Service
4 Corporation (AEPSC).

5 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND EMPLOYMENT
6 BACKGROUND.**

7 A. I received a Bachelor of Science Degree in Electrical Engineering in 1985 from West Virginia
8 Institute of Technology and a Masters Degree in Business Administration from Averett
9 University in 1998. I hold the Certified Energy Manager (CEM) designation and completed
10 the American Electric Power (AEP) / Ohio State University Management Program in 1995.

11 I joined Appalachian Power Company (APCo or Company) in 1985 as an electrical
12 engineer in Charleston, West Virginia. I have held several other positions of increasing
13 responsibility within APCo and AEPSC including Energy Services Engineer, Energy Services
14 Coordinator, Energy Services Supervisor, Demand Side Management Program Supervisor,
15 Key Account Manager, and National Account Executive. As Demand Side Management
16 Program Supervisor, from 1991 to 1995, I was responsible for the design, contractor selection,
17 implementation, marketing, advertising and data tracking of Demand Side Management
18 (DSM) programs in APCo's Virginia and West Virginia service territories. I also assisted with

1 evaluation efforts associated with those initiatives. I have served in my current role as
2 Manager – Consumer Programs since August 2008.

3 **Q. WHAT ARE YOUR DUTIES AS MANAGER – CONSUMER PROGRAMS?**

4 A. The Consumer Programs organization provides support to the AEP operating companies on a
5 variety of issues related to the development and implementation of energy efficiency programs.
6 These duties can include assistance to operating company personnel with programs and
7 program plan development, review of various market-related studies, coordination of certain
8 demand response initiatives, and other general support on an as-needed basis. However, the
9 administration, management and implementation of programs, including final program design,
10 are decentralized functions and are the responsibility of the individual AEP operating
11 companies.

12 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

13 A. My testimony will discuss how and why the Company undertook the DSM Potential Study
14 and associated DSM Action Plan reports (collectively referred to as the Study) recently
15 completed by Summit Blue Consulting, LLC (Summit Blue). I also will discuss the practical
16 considerations when implementing energy efficiency (EE) and demand response (DR)
17 programs (some of which have been referenced in the Study), program ramp up requirements,
18 the need for adequate staffing, and other observations.

19 **Q. WHY WAS THE DSM POTENTIAL STUDY INITIATED?**

20 A. From the Company's perspective, and for energy efficiency and demand response planning
21 purposes, it is important that APCo identify, to the extent possible, the estimated technical,
22 economic and achievable potentials, and related program options, within APCo as a first step

1 in evaluating a possible overall strategy and program mix. The Company sought a third-party
2 consultant to complete an initial assessment of the market potential and potential program
3 options. In late 2008 APCo selected Summit Blue to prepare the DSM potential study. APCo
4 and AEPSC personnel were involved in the contractor selection, regular progress reviews and
5 an initial review of the Study's suggestions.

6 Summit Blue was asked to prepare two items for the Company. The first was a DSM
7 Potential Study (Company Attachment B) to estimate the technical, economic and achievable
8 potential in the Company's Virginia service territory. Summit Blue also developed what it
9 described as Base, Low and High Cases for the achievable potential. Summit Blue's definition
10 of these potentials can be found on page 8 of the DSM Potential Study. The Study estimates
11 the potential levels for energy efficiency and demand response over a 20-year horizon. The
12 second item was a DSM Action Plan (Company Attachment A) where Summit Blue utilized
13 the results of the DSM Potential Study to develop a sample 5-year plan, one of many potential
14 program plans that could be considered by the Company, to present additional information on
15 a potential program mix, estimated program costs, necessary staffing levels, and other general
16 program information. The DSM Action Plan has been initially predicated on Summit Blue's
17 estimation of the Base Case of the achievable potential as identified in the DSM Potential
18 Study.

19 **Q. BRIEFLY DESCRIBE THE ENERGY EFFICIENCY AND DEMAND RESPONSE**
20 **PROGRAMS SUGGESTED BY THE STUDY.**

21 A. As stated on page 45, Section 6 of the DSM Action Plan, suggested plans were based on "best
22 practice" programs, or those that Summit Blue identified as top performers in previous studies

1 and/or successful programs from other states. The Study also indicates these suggested plans
2 are not intended to be operational in their current form. In other words, they are not ready for
3 implementation / deployment without further review, analysis, and possible modification.
4 Instead, the Study is a general guideline for more detailed program planning and represents an
5 interim step between the DSM potential analysis and the detailed plans needed to implement
6 programs. It provides a general sense of scope and scale and the resources necessary, such as
7 internal labor and program funding, for the possible implementation of programs in Virginia.

8 The Study, in general, suggests a mix of residential, commercial and industrial energy
9 efficiency and demand response programs. For the residential sector, this includes up to five
10 energy efficiency programs and one demand response program. For the commercial and
11 industrial sector, this includes up to three energy efficiency programs and one demand
12 response program. There are also two multi-sector programs: education / training and new
13 pilots/emerging technologies. The Study also suggests energy conservation kits, which could
14 include a variety of low-cost energy efficiency measures, as a possible program. General
15 details, including suggested high-level implementation strategies, are included in the Study
16 (program descriptions are summarized in the DSM Action Plan beginning on page 19, Section
17 E.3 and more fully described in the same document beginning on page 45, Section 6).

18 It should be noted that the Study references 2009 as Year 1 so that the estimated DSM
19 impact may be viewed in 2009 dollars for demonstrational purposes. The Study seeks to
20 address estimated values over an initial period of time, recognizing that the initial year of
21 implementation will certainly vary based upon the timing of policy actions and decisions
22 undertaken in Virginia.

1 Q. WHAT ARE SOME OF THE PRACTICAL CONSIDERATIONS THAT THE
2 COMPANY BELIEVES SHOULD BE CONSIDERED?

3 A. The Study suggests a broad portfolio of potential programs, covering all customer classes and
4 targeting market segments that may be willing to invest in energy efficiency. In general, the
5 Company believes that the Study is a good first step toward the evolution and development of
6 a cost-effective DSM program portfolio. However, the Company also recognizes there are
7 uncertainties, assumptions and/or limitations, some of which are mentioned in the Study, that
8 deserve careful consideration.

9 The DSM Action Plan, on pages 22 and 23, identifies several issues that must be
10 considered when reviewing and analyzing the Study suggestions. First, it will be very
11 challenging to convince business customers, given the current economic environment, to
12 voluntarily take on additional debt for the installation of cost-effective measures. The
13 Company also believes the current economic conditions may affect participation in residential
14 programs as well. This may be particularly true of residential programs targeted to the new
15 construction market. Second, the Study states that the largest sources of uncertainty regarding
16 the market potential estimates stem from the use of secondary information to profile some of
17 APCo's Virginia customers, and it is uncertain how the primarily regional and national
18 estimates used in the Study will apply. Third, only known enacted building/equipment codes
19 and standards were incorporated in the Study. The Company believes such standards will
20 change with time, and thus limit the overall potential in the future for utility-based programs.
21 Examples include lighting and motor standard improvements discussed in the testimony of
22 Company witness Castle. Finally, the level of energy and demand impacts identified in the

1 Study are based on historical economic conditions. It is possible that future economic
2 uncertainties will negatively affect the market potential.

3 Also, the Study does not take into consideration any provisions for customers who are
4 permitted to opt out. The Study discusses the possible effects of customer opt-out on pages 18
5 and 19 of the DSM Action Plan.

6 Consistent with the issues above, the Company would need to maintain the flexibility
7 to refine and adjust any proposed plan prior to its implementation in order to reflect such
8 factors as current market and economic conditions and regulatory requirements, and to
9 consider the implementation of programs that are deemed cost-effective at that time.

10 **Q. WHAT INTERNAL INFRASTRUCTURE / INTERNAL STAFFING WOULD BE**
11 **REQUIRED?**

12 A. The Study suggests that, on average, one full time equivalent (FTE) would be needed for each
13 \$1 to \$3 million invested in energy efficiency programs if such programs are largely
14 outsourced to implementation contractors (see Section 7 of the DSM Action Plan.).

15 This internal staffing would likely include a DSM program manager along with a team of
16 program coordinators. Company DSM staff would interact with contractors regularly to
17 ensure, among other things, that: (a) the utility and the implementation contractor are in sync,
18 (b) program rules are being followed, (c) policy issues are addressed, (d) data is being
19 collected and tracked in the appropriate manner, (e) forms, contracts, and agreements are
20 managed appropriately, (f) customer satisfaction issues are addressed, (g) marketing efforts are
21 achieved, and (h) the quality of the contractor performance is assured. Staffing could change
22 in relation to overall program portfolio size and scope.

1 APCo Virginia's DSM staff would also receive assistance from other Company and
2 AEPSC departments for such areas as marketing, centralized data repositories, load research,
3 policy, metering, and program evaluation expertise to supplement services available from the
4 implementation contractor(s) and/or to provide specific guidance.

5 **Q. CAN YOU ADDRESS TIMELINES ASSOCIATED WITH PROGRAM**
6 **IMPLEMENTATION?**

7 A. The Company agrees with the Study's approach of a multi-year program portfolio approach.
8 If, for example, a single year program approach is used and the one-year window begins upon
9 program approval, the Company would have to: commence the Request for Proposal (RFP)
10 process, select a contractor (who would ultimately build necessary labor and program
11 infrastructure), finalize necessary documentation, initiate marketing efforts, and perform
12 program implementation requirements. In short, little time may be left to operate the program.

13 Unless that program is extended, program implementation contractors could, and probably
14 would, pull up stakes at the end of the one-year term. As a result, program momentum could
15 be lost. Additionally, one might expect higher costs from program implementation contractors
16 for a single year program due to the significant up-front, one-time investment required to
17 establish an office, develop the necessary trade ally or other networks, hire and train staff, and
18 perform the other necessary activities required to ramp up a program. Finally, it may not be
19 possible to effectively evaluate the program within a one-year time frame.

20 **Q. FOR ANY FUTURE PROGRAM PORTFOLIO, WOULD THE COMPANY INITIATE**
21 **ALL PROGRAMS AT ONCE?**

22 A. From a practical standpoint, RFPs for an entire program portfolio would not likely be issued

1 simultaneously. APCo believes that programs would most effectively be implemented when
2 rolled out in stages. This would allow for internal staffing to be kept at a reasonable level and
3 provide the opportunity to implement programs, or portions of programs, that will be cost
4 effective. A program ramp up strategy would stagger the issuance of RFPs to allow the
5 Company's DSM staff to devote adequate resources for each individual program to find and
6 evaluate the most qualified contractors, to establish needed processes, and to implement the
7 program, to the extent possible, in a seamless and structured manner.

8 The timeline associated with program ramp up would ultimately depend upon a number
9 of factors including the number of programs in the portfolio, their complexity, and staffing
10 requirements. In any event, a reasonable program ramp up strategy, which would be
11 determined once the Company's program portfolio is finalized, should facilitate a more
12 manageable process.

13 **Q. HOW WOULD DATA RELATED TO CUSTOMER PARTICIPATION, ENERGY**
14 **EFFICIENCY MEASURE IMPACTS AND OTHER PROGRAM METRICS BE**
15 **TRACKED?**

16 A. AEPSC is in the process of developing a centralized data tracking system for use by all AEP
17 operating companies, including APCo. Data collected by the program implementation
18 contractor(s), provided in electronic format to APCo, would be mapped into this system. The
19 tracking system will provide, among other things, ongoing performance metrics and program
20 reporting for Company DSM staff.

21 **Q. IS THERE A NEED FOR AN APPROPRIATE EVALUATION, MEASUREMENT**
22 **AND VERIFICATION (EM&V) PROCESS?**

1 A. Yes. While the Company has not yet determined a specific EM&V process, it and/or its
2 contractor(s) would follow industry-accepted standards when performing program evaluation
3 functions. EM&V rules or guidelines may be necessary, perhaps even at a statewide level, to
4 ensure that each utility clearly understands how and when program impacts (energy and
5 demand) would be counted toward any established goal or target. The Study provides a high-
6 level EM&V plan for the Company's consideration beginning on page 125 of the DSM Action
7 Plan.

8 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

9 A. Yes, it does.

**DIRECT TESTIMONY OF
WILLIAM K. CASTLE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUE-2009-00023**

1 **Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?**

2 **A.** My name is William K. Castle and my business address is 1 Riverside Plaza, Columbus,
3 Ohio 43215.

4 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

5 **A.** I am employed by American Electric Power Service Corporation (AEPSC), the parent
6 company of Appalachian Power Company (the Company or APCo). My title is Director
7 – Demand Side Management and Resource Planning.

8 **Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

9
10 **A.** I received a Bachelor's of Science Degree in Mechanical Engineering in 1988 from
11 Tulane University and a Masters Degree in Business Administration in Finance from The
12 University of Texas - Austin in 1998. I hold the Chartered Financial Analyst designation.
13 In my current capacity, I am engaged in the development of the Company's Integrated
14 Resource Plan (IRP) with attention to the employment of Demand Side Management
15 (DSM), including demand response (DR) and energy efficiency (EE). Previous to my
16 current position, I oversaw the capital and O&M budgets for AEPSC. Prior to joining
17 AEPSC, I was employed by NiSource, formally Columbia Energy Group, and held
18 positions in Corporate Finance and Financial Planning.

19 **Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY IN ANY
20 REGULATORY PROCEEDINGS?**

21 **A.** Yes. I have filed testimony before the Oklahoma Corporation Commission on behalf of
22 Public Service Company of Oklahoma in a DSM proceeding; filed testimony and testified
23 before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power

1 Company supporting DSM cost-effectiveness; and filed testimony and testified before the
2 Public Utility Commission of Ohio on behalf of Columbus Southern Power and Ohio
3 Power Company in their ESP filings in regard to the advanced energy, energy efficiency
4 and peak demand reduction benchmarks.

5 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

6 A. There is a considerable range of possible EE/DR response levels that are deemed
7 “achievable” by utility DSM programs. However, some of the measures that have
8 accounted for utility program EE attainment in other states may not be available to APCo
9 for use in utility programs in similar quantities. Because of the uncertainties associated
10 with these EE measures, a shorter-term goal is more practical than a long-term goal. A
11 periodic assessment, and, if warranted, a periodic recalibration of the goal will align
12 efforts in this area with prevailing conditions.

13 Implementation of cost effective DSM programs will likely result in rate
14 increases, at least initially. All customers, collectively, should see savings over the long
15 term. This dynamic can be assessed through the use of four possible tests: the Total
16 Resource Cost (TRC) Test , Ratepayer Impact Measure (RIM) Test, Utility Cost Test and
17 Participant Test. The Company advocates the use of the TRC Test as a primary screen.

18 APCo suggests a shorter-term goal (i.e., less than 15 years) of installing energy
19 efficiency assets designed to achieve an annual reduction in consumption equivalent to
20 2% of APCo’s 2008 Virginia energy consumption in five years. It is expected that those
21 energy efficiency assets would effect a similar level of reduction-2% of 2008’s peak
22 demand. The goal would also be for an additional 3% of demand reduction from demand
23 response programs that would result in a reduction in peak demand equivalent to 5% of

1 2008 peak demand, subject to the opt-out issues discussed by Mr. Thomas in his
2 testimony.

3 **Q. WHAT INFORMATION DID YOU RELY ON TO ADDRESS THE QUESTIONS**
4 **POSED BY THE STATE CORPORATION COMMISSION IN ITS ORDER OF**
5 **APRIL 30, 2009?**

6 A. I relied upon my experience as the Director of DSM and Resource Planning and the
7 Summit Blue DSM Market Potential Study (the "Study"), attached to the Company's
8 comments. The Study is the Company's primary basis for describing the possible ranges
9 of DR and EE, as well as the costs associated with attaining levels within those ranges.

10 The Study estimated the technical, economic and achievable potential of various
11 DSM measures and describes three DSM program cases within the achievable range that
12 are designed to attain different levels of energy consumption and peak demand reductions
13 given different spending levels:

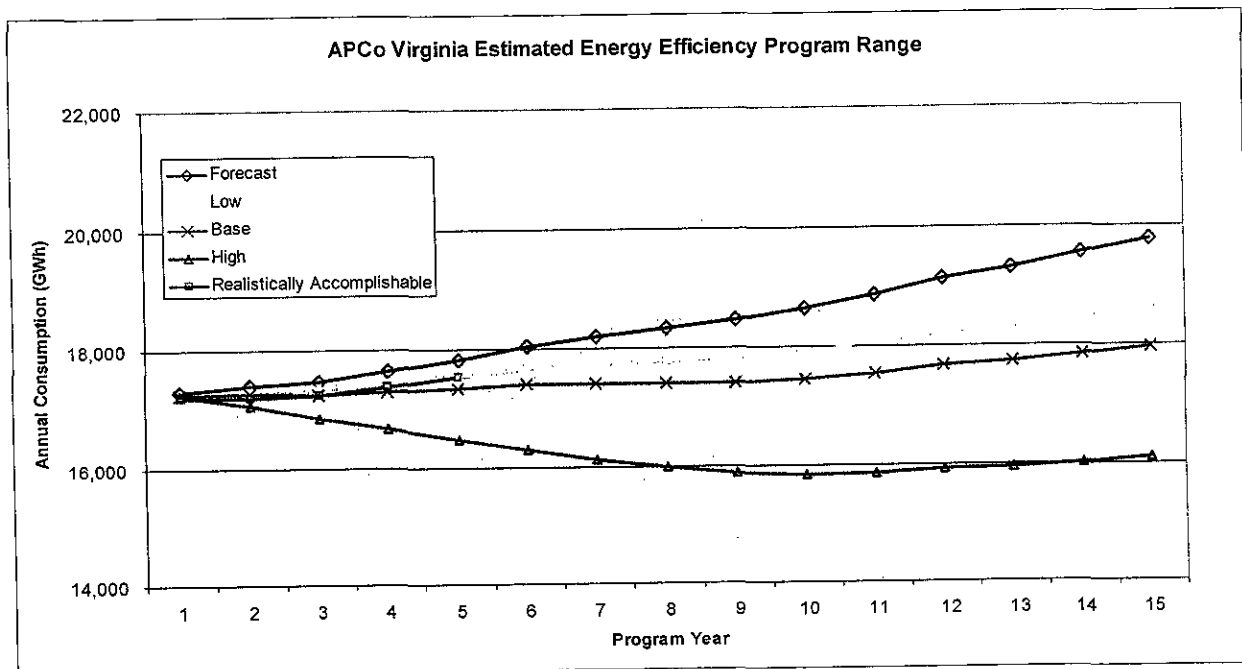
- 14 1. A Base Case representing what "best practices" utilities, as defined by
15 Summit Blue, have historically spent and achieved;
- 16 2. A High Case representing the most aggressive and costly program; and
- 17 3. A Low Case, which has lower program costs and "average" results.

18 These three cases illustrate the range of possible programs and likely program costs and
19 are used throughout the Study and my testimony. Having a range of possible DSM
20 Programs and costs provides the Company with a foundation upon which it can base its
21 on-going policy and program decisions. The Company's reliance on a range of options to
22 guide its implementation decisions reflects its beliefs, and its experiences, that
23 maintaining flexibility in this area is of the utmost importance to electric utilities, the
24 states that regulate them, and the customers.

1 Q. PLEASE DESCRIBE THE RANGE OF CONSUMPTION AND PEAK LOAD
2 REDUCTIONS REPRESENTED BY THE THREE CASES (SCC QUESTION 6).

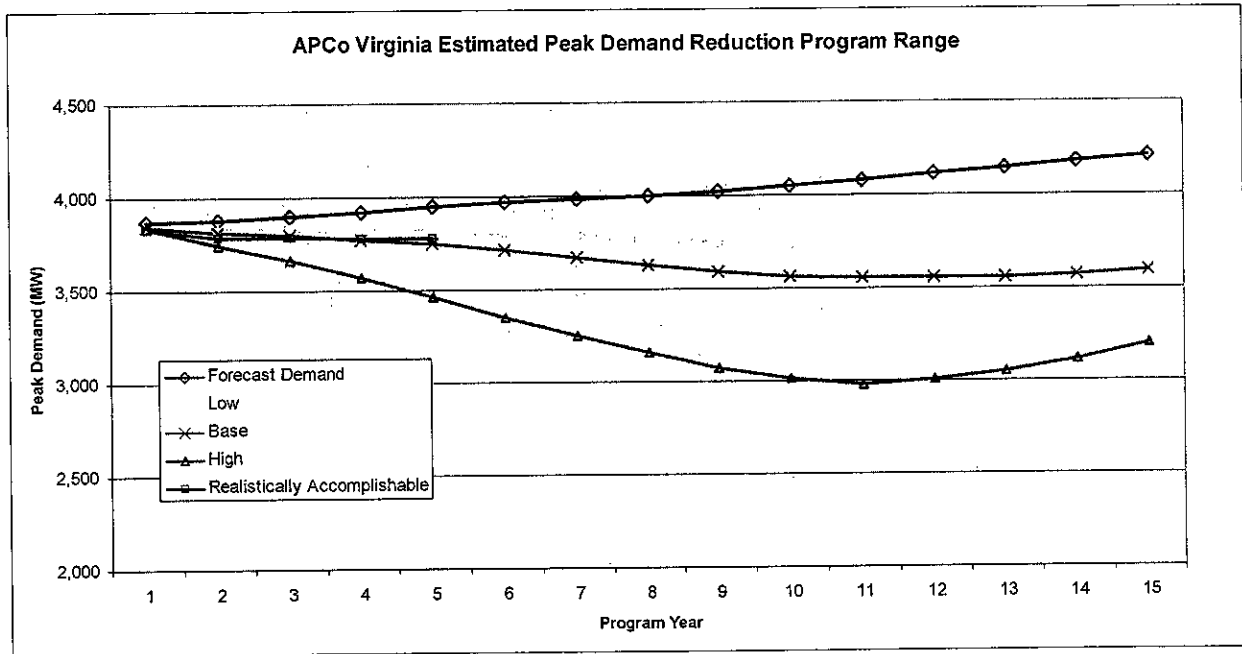
3 Figure 1 below shows the effects of cumulative energy reductions over a fifteen year
4 period, as estimated by the Study. Figure 2 shows the effects of peak demand reductions
5 that would result from the combination of EE programs and DR programs. In the Figures,
6 the Forecast shows what consumption/peak demand would be in the absence of any
7 programs. Exhibit WKC-1 shows the detailed, year-by-year break out of the three
8 Summit Blue cases as a percentage of 2008 consumption and peak demand, as well as the
9 incremental, annual reductions in relation to the previous year's peak
10 demand/consumption.

11 Figure 1



12
13
14
15

1 Figure 2



2
3

4 **Q. WHAT IS AN ACHIEVABLE, COST-EFFECTIVE ENERGY CONSERVATION**
5 **AND DEMAND RESPONSE TARGET THAT CAN BE REALISTICALLY**
6 **ACCOMPLISHED THROUGH THE COMPANY'S DEMAND-SIDE**
7 **MANAGEMENT PORTFOLIO (SCC QUESTION 1)?**

8 **A.** APCo is of the opinion that installing energy efficiency and demand response assets
9 designed to achieve savings equivalent to approximately 2% of the energy consumed in
10 2008 and 5% of 2008 peak demand is realistically accomplishable within 5 years of
11 program initiation, assuming current assumptions hold true. These levels are materially
12 aligned with the Study's Low Case and represent a result that is "realistically
13 accomplishable." These levels are inclusive of all customers, as are all of the Figures
14 presented here. Any provision that allows for customers to "opt out" may affect both the
15 absolute reductions and the reductions attributable to a utility program.

16 **Q. DOES THE COMPANY BELIEVE IT IS ENDORSING A "LOW" CASE?**

1 A. No. The Company believes the “Low Case” described in the Study is a bit of a
2 misnomer. The “Low” case describes attaining a level of energy efficiency and demand
3 reduction that is “average.” The Base Case assumes achievement of a “best practices”
4 pace in three to four years and adequate funding. Given the practical considerations
5 discussed by Witness Nichols, the desire to consider all customers, and the uncertainty of
6 the future, the Company feels that it is more prudent to plan for a level of DSM that is
7 truly “realistically accomplishable,” within a time frame that acknowledges the
8 uncertainty of the future.

9 There is also a disparity between the timing and certainty of costs and benefits.
10 While costs are incurred in current periods, the benefits are realized over time spans as
11 long as 25 years. It is more difficult to value those benefits, with confidence, than it is to
12 assess the probable costs.

13 The Company’s interpretation of the term “realistically accomplishable,” which is
14 distinct from what is “accomplishable at all costs,” recognizes that the most important
15 variable affecting the level of energy efficiency/demand reduction within a given
16 timeframe is program costs, which are primarily the costs that the Company must pay its
17 customers to encourage and reward participation. Figure 3 below demonstrates clearly
18 that greater energy efficiency achievement is directly linked to increased program costs.
19 By increasing the amount of customer incentives offered, and thus the program costs,
20 there is greater participation, and thus greater energy and demand savings. However,
21 those increased costs must be borne by all customers with savings more speculative and
22 certainly further off into the future.

1 motors becomes effective in 2010. The Study bases 35-40% of its achievable savings on
2 programs addressing residential compact fluorescent lights (CFL) and commercial
3 motors, which, in the absence of other, incrementally effective lighting and motor
4 measures, will greatly affect the mix of measures offered, and thus cost and impact
5 estimates. It isn't that those savings won't be realized, they just shouldn't be attributable
6 to a utility program.

7 It is impossible to predict the future. Codes and standards might usurp all
8 efficiency that was contemplated for utility programs, or the future may provide even
9 more opportunities to achieve and assign EE/DR savings to utility programs. Having
10 shorter term goals explicitly acknowledges this fact. It does not mean EE/DR programs
11 cannot or should not persist well into the future, it simply allows for a periodic re-
12 evaluation.

13 **Q. WHY HAS THE COMPANY BASED ITS TARGETS ON 2008 PEAK DEMAND**
14 **AND ENERGY CONSUMPTION LEVELS?**

15 A. The Company's target needs to be based on a fixed and known value, because it must
16 plan for and procure discrete amounts of demand-side assets. If a target is based on a
17 future (forecasted) value, changes in the forecasted load in the interceding years will
18 affect the absolute amount of EE/DR planned and procured. These constant adjustments
19 will engender varying and perhaps volatile levels of annual program investment.

20 **Q. DOES THE STUDY QUANTIFY THE BENEFITS TO THE CUSTOMERS FROM**
21 **THE ATTAINMENT OF EACH OF THE THREE PROGRAM CASES (SCC**
22 **QUESTION 7)?**

23 A. Yes. The calculated benefits to the utility system and all its ratepayers are depicted in
24 two primary ways: the avoided cost of energy and the avoided cost of capacity. Since

1 the investment in energy efficiency programs produces benefits that last for a number of
 2 years, in this analysis it is the “present value” of those benefits (avoided capacity and
 3 energy costs) for the life of an investment that must be considered. For example, the
 4 investment in an energy efficiency program in Year 1 will represent a cost in Year 1; the
 5 benefits, however, will be achieved over a number of years, we’ve assumed an average of
 6 10. In order to show the cumulative benefits achieved during the 5-year program, we
 7 calculated the present value of the benefits (which span 15 years) associated with those
 8 investments and show that in the top Benefits table below. The present value of the
 9 benefits calculated to accrue from investment in the 15-year program is shown in the
 10 bottom Benefits table.

Benefits of the First Five-Years of Investment in EE/DR (\$ thousands)				
	Avoided Capacity	Avoided Energy	Total Resource Costs (undiscounted)	PV of Benefits
Low	69,719	118,957	188,676	93,720
Base	135,609	203,775	339,384	168,751
High	390,822	561,808	952,630	464,310

Benefits of Fifteen Years of Investment in EE/DR (\$ thousands)				
	Avoided Capacity	Avoided Energy	Total Resource Benefits (undiscounted)	PV of Benefits
Low	303,271	556,452	859,722	287,675
Base	501,692	887,320	1,389,012	538,379
High	1,026,502	1,746,126	2,772,628	1,119,048

11

12

13

14 The annual benefits can be seen for the programs in Exhibit WKC- 2

15 **Q. WHAT IS THE RANGE OF COSTS THAT CONSUMERS WOULD PAY TO**

16 **ACHIEVE THE RANGE OF OUTCOMES (SCC QUESTION 7)?**

1 A: Costs for the programs are in two pieces, the costs borne by the Company on behalf of all
2 customers (program costs) as shown in the first table below and the costs paid solely by
3 participating customers (net participant costs) shown in the second table below.

Five-Year Costs of Program Proposals EE/DR (\$ thousands)				
	Utility Program Costs	Net Participant Costs	Total Resource Costs (undiscounted)	PV of Costs
Low	89,239	27,309	116,548	87,260
Base	134,000	37,452	171,452	126,049
High	375,854	65,394	441,248	319,667

Fifteen-Year Costs of Program Proposals EE/DR (\$ thousands)				
	Utility Program Costs	Net Participant Costs	Total Resource Costs (undiscounted)	PV of Costs
Low	448,180	118,115	566,295	267,903
Base	660,209	160,953	821,162	390,683
High	1,338,437	184,637	1,523,074	785,539

4
5 Exhibit WKC-3 has the full, year-by year breakout of program and net participant costs.

6 **Q. DO THE COSTS INCLUDE ALL COSTS THAT RATEPAYERS COULD INCUR**
7 **DUE TO THE IMPLEMENTATION OF THE PROGRAMS?**

8 A. No. First, net lost revenues, the costs associated with recovering the same amount of
9 fixed costs with fewer kWhs, were not evaluated as part of the Study. Although they are
10 not considered as part of the TRC test, and are not incremental costs associated with
11 program implementation, net lost revenue recovery will impart upward pressure on rates.

12 Second, to place demand-side investments on par with supply-side investments, it
13 is necessary to compensate the utility for the use of its capital. This statutorily allowed
14 return on the company's capital can take many forms but was not quantified in the Study.

15

1 **Q. DOES THE COMPANY HAVE ANY COMMENTS AS TO WHAT MAY BE THE**
2 **POTENTIAL IMPACT OF DEMAND SIDE MANAGEMENT PROGRAMS ON**
3 **ECONOMIC DEVELOPMENT IN THE COMMONWEALTH (SCC QUESTION**
4 **5)?**

5 A. Yes. The Company does not have a study or an analysis to quantify the net effect on
6 economic development that would result from implementation of EE/DR programs in its
7 Virginia service territory. However, from a broad, somewhat macro perspective,
8 certainly there will be jobs created as a result of the spending on efficiency and demand
9 response programs. On the other hand, due to such expenditures, there might be less
10 spent on other goods and services as consumers and companies reallocate their
11 expenditures.

12 In terms of electricity rates as a component of economic development, rates may
13 increase for certain customer classes depending upon how the Commission determines
14 issues related to cost recovery and administration of the opt-out provisions. If larger
15 customers are exempted, then economic development may be aided by the knowledge
16 that, for existing and/or prospective larger customers, their future electricity rates will not
17 be impacted by this component of the utility's costs. Also, assuming that measures are
18 cost-effective under the TRC Test, overall expenditures on electricity will be lower in the
19 longer term than they otherwise would have been through the use of traditional supply
20 options.

21 **Q. WHAT ARE THE INDUSTRY-RECOGNIZED TESTS USED TO DETERMINE**
22 **COST-EFFECTIVE CONSUMPTION AND PEAK LOAD REDUCTIONS (SCC**
23 **QUESTION 2)?**

1 A. There are five tests commonly employed to evaluate demand-side programs and
2 measures. The tests, which seek to examine cost effectiveness from different
3 perspectives, are:

4 1. Total Resource Cost Test (TRC Test): This test compares the total cost
5 (the incremental cost over the standard technology) of a proposed technology, such as a
6 CFL light bulb, including installation and associated utility administrative costs (the
7 installed cost), to the costs of supply alternatives. A measure, or program, is cost-
8 effective if the present value of its avoided costs (energy and capacity) and any tax
9 incentives are greater than the installed cost. The TRC Test ignores the issue of who
10 pays for the measure, rather it views the measure from the perspective of “all ratepayers.”
11 Avoided costs are the cost to build or buy the marginal unit of capacity and associated
12 infrastructure and/or the costs to produce the marginal unit of energy.

13 2. Ratepayer Impact Measure (RIM Test): This test evaluates cost
14 effectiveness from the perspective of the ratepayer and gauges whether or not retail rates
15 will be affected. A program is cost-effective under this test if the utility’s avoided costs
16 are greater than the sum of the program’s costs and the lost revenues that result from
17 reduced throughput.

18 3. Program Administrator or Utility Cost Test: This test evaluates the
19 proposed program or technology from the perspective of the utility, and compares the
20 administrative costs and the costs of the utility-paid participant incentive to the costs of
21 the supply alternative. This measure is equivalent to determining whether the utility’s
22 revenue requirement will increase or decrease as a result of implementation.

23 4. Participant Test: This test measures cost-effectiveness from the
24 perspective of the participant. The participant’s benefits are a reduced bill that results

1 from reduced throughput, any tax benefit, and the participant incentive offered by the
2 utility. The cost is the cost to install the measure(s) and does not include any of the
3 administrative costs.

4 5. Societal Test: The Societal Test measures cost effectiveness from the
5 perspective of society as a whole. The Virginia State Corporation Commission has
6 previously stated that it does not have the statutory authority to apply this standard and
7 APCo agrees it should not be adopted in the Commonwealth.

8 **Q. WHICH TEST DOES THE COMPANY RECOMMEND THAT THE**
9 **COMMISSION ADOPT?**

10 A. APCo recommends that the Commission adopt the TRC Test as the first and primary
11 screen. This test puts the proposed technology or program on the same basis as a supply
12 option and considers the costs in their entirety, regardless of who pays. Evaluating
13 proposed technology and programs under the TRC Test keeps the utility from
14 subsidizing, and thus endorsing, measures that would not be economical on their own.

15 The Commission can incorporate certain of the other tests into its consideration in
16 order to shape program design, but these tests do not necessarily need to be met or be
17 granted equal weight in order to make a determination of a program's merit. Different
18 programs will have different scores owing to their unique cost and impact characteristics.
19 Presenting all of the scores might help enumerate the trade-offs made in program design,
20 and the impact of the amount of participant incentive offered.

21 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

22 A. Yes.

Achievable Ranges – Energy Consumption Reductions

Annual Energy Efficiency Reductions from Previous Year

program year	Low	Base	High
1	0.3%	0.3%	0.3%
2	0.2%	0.4%	1.5%
3	0.3%	0.6%	1.9%
4	0.4%	0.7%	1.9%
5	0.4%	0.8%	2.3%
6	0.5%	0.9%	2.3%
7	0.5%	0.8%	2.0%
8	0.5%	0.8%	1.7%
9	0.5%	0.8%	1.5%
10	0.5%	0.8%	1.4%
11	0.5%	0.8%	1.3%
12	0.5%	0.7%	1.2%
13	0.4%	0.7%	1.0%
14	0.4%	0.7%	1.0%
15	0.4%	0.6%	0.9%

Cumulative Installed Energy Efficiency Reductions from Base Year

program year	Low	Base	High
1	0.3%	0.3%	0.3%
2	0.5%	0.7%	1.8%
3	0.8%	1.3%	3.6%
4	1.2%	2.0%	5.4%
5	1.6%	2.8%	7.6%
6	2.1%	3.6%	9.7%
7	2.6%	4.4%	11.5%
8	3.1%	5.2%	13.1%
9	3.5%	6.0%	14.5%
10	4.0%	6.7%	15.7%
11	4.5%	7.4%	16.9%
12	5.0%	8.2%	17.9%
13	5.4%	8.8%	18.9%
14	5.9%	9.5%	19.7%
15	6.3%	10.1%	20.5%

- Achievable Ranges Peak Demand Reductions

Cumulative Winter Peak Demand Reductions From EE/DR
from Base Year

program year	Low	Base	High
1	0.7%	0.8%	1.0%
2	1.2%	1.7%	3.5%
3	1.9%	2.7%	6.3%
4	2.6%	3.9%	9.4%
5	3.5%	5.4%	13.3%
6	4.5%	7.0%	16.9%
7	5.5%	8.6%	20.2%
8	6.5%	10.2%	23.2%
9	7.5%	11.7%	25.8%
10	8.5%	13.2%	28.2%
11	9.5%	14.7%	30.4%
12	10.5%	16.1%	32.4%
13	11.4%	17.5%	34.3%
14	12.4%	18.8%	36.0%
15	13.3%	20.1%	37.5%

Cumulative Winter Peak Demand Reductions From DR
from Base Year

program year	Low	Base	High
1	0.3%	0.4%	0.6%
2	0.6%	0.8%	1.2%
3	0.9%	1.2%	1.8%
4	1.2%	1.6%	2.5%
5	1.6%	2.1%	3.2%
6	2.0%	2.7%	4.0%
7	2.4%	3.2%	4.8%
8	2.8%	3.7%	5.6%
9	3.2%	4.3%	6.4%
10	3.6%	4.8%	7.2%
11	4.0%	5.4%	8.1%
12	4.4%	5.9%	8.9%
13	4.9%	6.5%	9.7%
14	5.2%	7.0%	10.5%
15	5.6%	7.5%	11.2%

Cumulative Winter Peak Demand Reductions From EE
from Base Year

program year	Low	Base	High
1	0.4%	0.4%	0.4%
2	0.9%	0.9%	2.3%
3	1.0%	1.5%	4.5%
4	1.3%	2.3%	7.0%
5	1.9%	3.3%	10.1%
6	2.5%	4.4%	12.9%
7	3.1%	5.4%	15.5%
8	3.7%	6.4%	17.6%
9	4.3%	7.4%	19.4%
10	4.9%	8.4%	21.0%
11	5.5%	9.3%	22.3%
12	6.0%	10.2%	23.5%
13	6.6%	11.0%	24.6%
14	7.1%	11.9%	25.5%
15	7.6%	12.6%	26.3%

EE/DR Benefits – Residential EE Programs

Total Value Residential (\$thousands)

program year	Low	Base	High
1	1,286	1,286	1,286
2	2,294	3,271	8,378
3	3,467	5,610	16,110
4	5,580	9,506	28,338
5	8,425	14,723	43,872
6	11,512	20,215	57,758
7	14,529	25,376	68,948
8	20,442	35,331	90,395
9	24,264	41,501	101,261
10	28,054	47,444	110,697
11	30,092	51,733	118,320
12	32,652	54,753	115,282
13	35,075	57,268	110,375
14	36,815	58,514	102,435
15	37,872	58,410	91,281
16-25			
Total	\$ 292,359	\$ 484,941	\$ 1,064,736
Total (PV)	\$ 114,990	\$ 191,741	\$ 442,643

Capacity Value Residential (\$thousands)

program year	Low	Base	High
1	351	351	351
2	967	1,354	3,684
3	1,385	2,204	6,864
4	2,614	4,435	14,300
5	4,653	8,165	25,998
6	6,282	11,119	33,919
7	8,079	14,254	41,187
8	9,903	17,365	47,661
9	11,768	20,476	53,523
10	13,657	23,580	58,813
11	14,495	25,547	62,566
12	15,754	27,205	61,353
13	16,836	28,484	59,021
14	17,656	29,232	55,069
15	17,943	28,976	48,563
16-25			
Total	\$ 142,341	\$ 242,727	\$ 572,871
Total (PV)	\$ 56,155	\$ 95,999	\$ 238,374

Energy Value Residential (\$thousands)

program year	Low	Base	High
1	935	935	935
2	1,327	1,817	4,694
3	2,082	3,406	9,246
4	2,967	5,071	14,037
5	3,772	6,558	17,873
6	5,231	9,097	23,840
7	6,450	11,122	27,761
8	10,538	17,966	42,734
9	12,496	21,026	47,738
10	14,397	23,884	51,884
11	15,597	26,186	55,754
12	16,899	27,548	53,929
13	18,239	28,784	51,354
14	19,159	29,282	47,367
15	19,929	29,434	42,718
16-25			
Total	\$ 150,018	\$ 242,214	\$ 491,864
Total (PV)	\$ 58,835	\$ 95,742	\$ 204,269

Total Value C&I (\$thousands)

program year	Low	Base	High
1	1,319	1,319	1,319
2	2,060	2,861	7,108
3	3,348	5,304	14,208
4	5,196	8,630	23,236
5	7,285	12,254	33,902
6	10,148	17,078	47,346
7	12,501	21,031	57,255
8	16,804	31,607	83,570
9	22,020	36,965	94,660
10	25,109	42,079	104,443
11	26,921	46,227	113,905
12	28,948	49,196	114,644
13	30,694	51,471	110,835
14	31,728	52,553	110,479
15	32,288	52,962	103,391
Total	\$ 258,368	\$ 431,538	\$ 1,023,323
Total (PV)	\$ 102,188	\$ 170,025	\$ 413,798

Capacity Value C&I (\$thousands)

program year	Low	Base	High
1	131	131	131
2	401	564	1,360
3	652	1,049	2,776
4	1,231	2,068	5,510
5	2,095	3,543	9,797
6	2,750	4,643	12,995
7	3,396	5,731	15,836
8	4,038	6,818	18,348
9	4,686	7,914	20,613
10	5,342	9,018	22,697
11	5,606	9,733	24,269
12	5,957	10,236	24,064
13	6,131	10,388	22,993
14	6,280	10,513	21,969
15	6,295	10,461	20,008
Total	\$ 54,992	\$ 92,811	\$ 223,367
Total (PV)	\$ 22,198	\$ 37,360	\$ 92,527

Energy Value C&I (\$thousands)

program year	Low	Base	High
1	1,186	1,186	1,188
2	1,659	2,298	5,748
3	2,697	4,255	11,431
4	3,964	6,562	17,726
5	5,190	8,711	24,105
6	7,397	12,434	34,351
7	9,105	15,300	41,420
8	14,786	24,789	65,222
9	17,334	29,050	74,067
10	19,768	33,062	81,746
11	21,314	36,495	89,636
12	22,991	38,960	90,580
13	24,562	41,063	90,842
14	25,447	42,040	88,511
15	25,992	42,501	83,383
Total	\$ 203,375	\$ 338,727	\$ 799,956
Total (PV)	\$ 79,990	\$ 132,665	\$ 321,271

Total Capacity Value DR (\$thousands)

program year	Low	Base	High
1	71	528	792
2	244	1,803	2,704
3	352	2,599	3,899
4	632	4,669	7,004
5	1,032	7,628	11,439
6	1,306	9,668	14,487
7	1,586	11,728	17,592
8	1,887	13,952	20,928
9	2,207	16,318	24,477
10	2,538	18,769	28,153
11	2,879	21,290	31,936
12	3,226	23,857	35,785
13	3,576	26,445	39,668
14	3,926	29,034	43,551
15	4,274	31,604	47,407
Total	\$ 29,736	\$ 219,881	\$ 329,821
Total (PV)	\$ 11,668	\$ 86,277	\$ 129,416

Capacity Value C&I DR (\$thousands)

program year	Low	Base	High
1	46	359	538
2	157	1,225	1,838
3	227	1,767	2,651
4	408	3,176	4,763
5	666	5,188	7,782
6	844	6,573	9,859
7	1,025	7,984	11,976
8	1,219	9,501	14,252
9	1,427	11,116	16,674
10	1,641	12,789	19,184
11	1,863	14,512	21,768
12	2,088	16,267	24,400
13	2,315	18,037	27,056
14	2,542	19,809	29,714
15	2,768	21,570	32,355
Total	\$ 19,235	\$ 149,875	\$ 224,812
Total (PV)	\$ 7,545	\$ 58,788	\$ 88,182

Capacity Value Res DR (\$thousands)

program year	Low	Base	High
1	25	169	254
2	87	577	866
3	125	832	1,248
4	224	1,494	2,240
5	366	2,438	3,657
6	463	3,085	4,628
7	562	3,744	5,616
8	668	4,451	6,676
9	780	5,202	7,803
10	897	5,979	8,969
11	1,017	6,778	10,167
12	1,139	7,590	11,385
13	1,261	8,408	12,612
14	1,384	9,224	13,837
15	1,505	10,034	15,051
Total	\$ 10,501	\$ 70,006	\$ 105,010
Total (PV)	\$ 4,123	\$ 27,489	\$ 41,234

Total EE Program Costs (\$thousands)

program year	Low	Base	High
1	11,147	11,147	11,147
2	8,231	13,494	54,955
3	9,733	16,711	63,436
4	12,356	21,689	79,198
5	16,366	28,651	102,353
6	17,831	30,911	100,258
7	17,893	30,418	86,291
8	17,650	29,502	73,710
9	17,448	28,673	63,584
10	17,380	28,142	56,636
11	17,328	27,655	51,334
12	17,232	27,094	46,759
13	16,927	26,090	41,059
14	16,851	25,610	38,364
15	16,646	24,873	35,027
Total	\$ 231,018	\$ 370,660	\$ 904,113
Total (PV)	\$ 113,509	\$ 181,643	\$ 484,195

EE C&I Program Costs (\$thousands)

program year	Low	Base	High
1	5,811	5,811	5,811
2	4,033	6,898	30,514
3	5,081	8,977	35,547
4	6,699	12,034	46,386
5	9,194	16,459	64,735
6	10,391	18,403	66,541
7	10,014	17,598	56,594
8	9,798	17,052	48,112
9	9,616	16,566	41,332
10	9,556	16,331	36,978
11	9,532	16,167	33,920
12	9,466	15,915	31,197
13	9,269	15,378	27,642
14	9,225	15,182	26,141
15	9,109	14,850	24,181
Total	\$ 126,794	\$ 213,601	\$ 575,630
Total (PV)	\$ 62,016	\$ 103,541	\$ 302,745

EE Residential Program Costs (\$thousands)

program year	Low	Base	High
1	5,336	5,336	5,336
2	4,198	6,595	24,441
3	4,652	7,734	27,889
4	5,657	9,655	32,812
5	7,172	12,191	37,618
6	7,440	12,508	33,717
7	7,879	12,819	29,696
8	7,852	12,450	25,598
9	7,832	12,106	22,253
10	7,824	11,811	19,658
11	7,796	11,488	17,414
12	7,765	11,179	15,563
13	7,658	10,713	13,417
14	7,625	10,429	12,224
15	7,537	10,043	10,846
Total	\$ 104,224	\$ 157,058	\$ 328,483
Total (PV)	\$ 51,492	\$ 78,103	\$ 181,450

EE/DR Costs –DR (Winter) Program Costs

Winter Total DR Program Costs (\$thousands)

program year	Low	Base	High
1	3,182	4,243	6,365
2	4,487	5,983	8,974
3	5,873	7,564	11,346
4	7,165	9,554	14,330
5	9,159	12,212	18,319
6	10,906	14,541	21,811
7	12,515	16,686	25,030
8	14,341	19,121	28,881
9	16,175	21,567	32,351
10	17,995	23,994	35,991
11	19,781	26,375	39,562
12	21,516	28,687	43,031
13	23,186	30,915	46,373
14	24,783	33,044	49,566
15	26,298	35,063	52,595
Total	\$ 217,162	\$ 289,549	\$ 434,324
Total (PV)	\$ 92,020	\$ 122,694	\$ 184,040

Winter C&I DR Program Costs (\$thousands)

program year	Low	Base	High
1	2,532	3,376	5,064
2	3,628	4,837	7,296
3	4,829	6,173	9,259
4	5,873	7,830	11,746
5	7,520	10,027	15,041
6	8,983	11,977	17,965
7	10,338	13,785	20,677
8	11,866	15,822	23,732
9	13,405	17,873	26,809
10	14,934	19,912	29,868
11	16,437	21,916	32,874
12	17,900	23,867	35,800
13	19,312	25,749	38,623
14	20,663	27,550	41,326
15	21,947	29,282	43,894
Total	\$ 179,967	\$ 239,956	\$ 359,934
Total (PV)	\$ 76,037	\$ 101,383	\$ 152,075

Winter Residential DR Program Costs (\$thousands)

program year	Low	Base	High
1	650	867	1,301
2	859	1,145	1,718
3	1,044	1,391	2,087
4	1,292	1,723	2,585
5	1,639	2,185	3,278
6	1,923	2,564	3,846
7	2,176	2,902	4,353
8	2,475	3,299	4,949
9	2,771	3,694	5,542
10	3,061	4,082	6,123
11	3,344	4,458	6,688
12	3,615	4,821	7,231
13	3,875	5,166	7,749
14	4,120	5,493	8,240
15	4,351	5,801	8,702
Total	\$ 37,195	\$ 49,593	\$ 74,390
Total (PV)	\$ 15,983	\$ 21,310	\$ 31,965

Summer Total DR Program Costs (\$thousands)

program_year	Low	Base	High
1	211	310	551
2	274	423	807
3	330	525	1,042
4	407	657	1,328
5	516	837	1,704
6	603	980	2,043
7	681	1,129	2,359
8	773	1,290	2,711
9	865	1,450	3,067
10	954	1,609	3,421
11	1,041	1,763	3,770
12	1,125	1,913	4,109
13	1,205	2,057	4,437
14	1,280	2,194	4,751
15	1,351	2,323	5,050
Total	\$ 11,618	\$ 19,471	\$ 41,150
Total (PV)	\$ 5,006	\$ 8,302	\$ 17,334

Summer C&I DR Program Costs (\$thousands)

program_year	Low	Base	High
1	136	200	355
2	177	273	520
3	213	339	672
4	263	424	857
5	333	541	1,100
6	390	640	1,319
7	440	730	1,524
8	500	834	1,753
9	559	938	1,983
10	617	1,041	2,213
11	674	1,141	2,439
12	728	1,239	2,660
13	780	1,332	2,873
14	830	1,421	3,078
15	876	1,506	3,273
Total	\$ 7,517	\$ 12,597	\$ 26,620
Total (PV)	\$ 3,237	\$ 5,368	\$ 11,208

Summer Residential DR Program Costs (\$ thousands)

program_year	Low	Base	High
1	75	110	196
2	97	150	286
3	117	186	370
4	144	233	471
5	183	297	604
6	214	351	723
7	241	400	835
8	273	456	959
9	305	512	1,084
10	337	568	1,208
11	367	622	1,330
12	397	675	1,449
13	424	725	1,564
14	451	772	1,674
15	475	818	1,778
Total	\$ 4,101	\$ 6,874	\$ 14,550
Total (PV)	\$ 1,769	\$ 2,834	\$ 6,126

Participant Net Costs (\$thousands)

program year	Low	Base	High
1	6,356	3,813	1,271
2	2,962	5,012	11,533
3	4,006	6,622	13,345
4	5,760	9,220	16,931
5	8,225	12,784	22,314
6	9,452	14,095	21,813
7	9,496	13,773	18,454
8	9,324	13,262	15,410
9	9,180	12,798	12,962
10	9,134	12,488	11,246
11	9,097	12,199	9,937
12	9,023	11,876	8,833
13	8,793	11,327	7,547
14	8,732	11,047	6,898
15	8,575	10,636	6,145
Total	\$ 118,115	\$ 160,953	\$ 184,637
Total (PV)	\$ 57,369	\$ 78,045	\$ 99,970



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DIRECT FAX: (502) 627-8722
kendrick.riggs@skofirm.com

June 30, 2009

VIA ELECTRONIC FILING

Joel H. Peck
Clerk, Virginia State Corporation Commission
Tyler Building, 1st Floor
1300 East Main Street
Richmond, VA 23219

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 Electric Utility Identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly
Case No. PUE-2009-00023

Dear Mr. Peck:

Attached please find the Direct Testimony of Lonnie E. Bellar on behalf of Kentucky Utilities Company d/b/a Old Dominion Power Company for filing in the above-referenced matter via electronic submission.

Should you have any questions, please do not hesitate to contact me.

Yours very truly,

Kendrick R. Riggs

KRR:ec

Enclosures

cc: C. Meade Browder Jr., Sr. Assistant Attorney General, Division of Consumer Counsel
David R. Eichenlaub, Division of Economics & Finance
Don R. Mueller, Esq., Office of General Counsel
Frederick D. Ochsenhirt, Esq., Office of General Counsel
Parties of Record

400001.134252/584712

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

**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 electric utility identified by)
Chapters 752 and 855 of the 2009 Acts)
of the Virginia General Assembly)**

CASE NO.
PUE-2009-00023

DIRECT TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT OF STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY D/B/A.
OLD DOMINION POWER COMPANY

Filed: June 30, 2009

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

2 A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates
3 for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company
4 ("LG&E") and an employee of E.ON U.S. Services, Inc., which provides services to
5 the KU and LG&E. My business address is 220 West Main Street, Louisville,
6 Kentucky. A statement of my education and work experience is attached to this
7 testimony as Appendix A.

8 **Q. Does KU provide retail electric service in the Commonwealth of Virginia?**

9 A. Yes. KU operates in Virginia under the name Old Dominion Power Company
10 ("KU/ODP") and provides retail electric service to approximately 30,000 Virginia
11 customers, which are in and around Wise (20,700), Lee (7,100), Russell (1,900),
12 Scott (50), and Dickenson Counties (300). This number of customers has remained
13 nearly unchanged for years.

14 KU/ODP maintains offices in Virginia at 1000 Park Ave., NW, Norton,
15 Virginia, and at 317 E. Morgan Ave., Pennington Gap, Virginia.

16 **Q. What is the purpose of your testimony?**

17 A. The purpose of my testimony is to respond to the questions addressed to generating
18 utilities in the Virginia State Corporation Commission's ("Commission") April 30,
19 2009 Order initiating this proceeding; however, KU/ODP continues to maintain that it
20 is not a "generating utility" for the purposes of this proceeding because it does not
21 own or operate any electric generating assets in Virginia.

22 **Q. What is an achievable, cost-effective energy conservation and demand response**
23 **target that can be realistically accomplished through the generating electric**
24 **utility's demand-side management portfolio?**

1 A. KU/ODP does not currently deploy demand-side management (“DSM”) or energy
 2 efficiency (“EE”) programs, but KU and its sister utility, LG&E, have had significant
 3 DSM/EE programs in place in Kentucky for a number of years. In 2007, KU and
 4 LG&E applied to the Kentucky Public Service Commission (“KPSC”) for approval of
 5 a suite of DSM/EE programs that the California Standard Practice Manual
 6 cost/benefit ratios showed to be cost-effective:¹

7 **Table 1**

8 **Benefit/Cost Ratios**

	Participants Test	Utility Cost Test	Ratepayer Impact Test	Total Resource Cost Test
Residential Conservation	4.19	1.37	0.60	1.50
Residential Load Management	Infinity	2.67	1.90	3.75
Commercial Load Management	Infinity	4.52	2.09	6.12
Res. Low Income Weatherization	Infinity	0.81	0.37	2.28
Commercial Conservation /Rebates	4.30	11.21	0.89	3.64
Residential High Efficiency Lighting	11.04	4.40	0.64	2.87
Residential New Construction	2.23	1.49	0.61	1.09
Residential HVAC Tune Up	7.66	1.13	0.62	1.10
Commercial HVAC Tune Up	20.32	2.04	0.53	1.79
*Customer Education & Public Information	n/a	0	0	0
*Dealer Referral Network	n/a	0	0	0
*Program Development and Admin.	n/a	0	0	0
Overall Portfolio	7.02	3.31	0.89	2.80

9 * Benefits are captured in analysis of supported programs
 10

¹ In the Matter of: the Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company Demand-Side Management for the Review, Modification, and Continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms, KY PSC Case No. 2007-00319, Application (July 19, 2007).

1 The approximate annual total cost of the projects KU and LG&E proposed is \$26
2 million, and the energy and demand savings the programs are projected to produce is
3 shown in Table 2 below:²

4 **Table 2**

Projected Annual Savings for all the Energy Efficiency Programs ³							
	2008	2009	2010	2011	2012	2013	2014
MWh	125,621	248,466	368,816	484,966	598,093	707,193	813,058
MW	47	95	142	186	229	267	303
MCF	490	978	1,482	1,939	2,406	2,818	3,209

5
6 The sum of these projected energy savings (3,346,213 MWh) amount to 1.2% of KU
7 and LG&E's combined projected energy requirements forecast for the same period
8 (approximately 269,206,000 MWh).⁴

9 Though KU and LG&E are considering proposing additional DSM/EE
10 programs in Kentucky this year, they believe that their current suite of such programs
11 represents a reasonably comprehensive set of cost-effective programs, and that their
12 projected energy and demand savings therefore can be "realistically accomplished,"
13 albeit on a smaller scale in the KU/ODP Virginia service territory (approximately
14 30,000 customers, whereas KU and LG&E have a combined Kentucky customer base
15 of over 900,000 customers). Also, challenges and conditions particular to the
16 KU/ODP service territory may alter the cost-effectiveness of certain DSM/EE
17 programs (e.g., geography and terrain may make implementing a load control device

² *Id.* at "LG&E and KU Energy Efficiency 2008-2014 Program Plan" at 9.

³ Energy impacts represent cumulative savings from initiatives beginning in 2008.

⁴ See *In the Matter of: the 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, KY PSC Case No. 2008-00148, 2008 IRP at 8-89 (April 21, 2008).

1 program more costly than it would be in parts of KU and LG&E's Kentucky service
2 territory).

3 One other challenge KU and LG&E have faced in their Kentucky service
4 territory is the opposition of the Kentucky Attorney General ("KYAG") and industrial
5 customers. For example, in KU's and LG&E's most recent DSM/EE application
6 proceeding, the KYAG opposed the expansion of existing programs and the creation
7 of new programs.⁵ Industrial customers have not been particularly active in KU and
8 LG&E's recent DSM/EE proceedings in Kentucky because, as I explain more fully
9 below, those customers were able to influence legislation effectively to exempt them
10 from participation in DSM/EE programs. They nonetheless participate in and
11 monitor KU and LG&E's DSM/EE proceedings through the intervention of the
12 Kentucky Industrial Utilities Customers, Inc.

13 **Q. What industry-recognized tests should be used in determining cost-effective**
14 **consumption and peak load reductions and what relative weighting should be**
15 **afforded to any test recommended for use by the respondent generating electric**
16 **utility?**

17 **A. KU/ODP believes that the set of four cost-benefit tests the KPSC currently employs,**
18 **i.e., those contained in the California Standard Practice Manual: Economic Analysis**
19 **of Demand-Side Programs and Projects ("Manual"), represents the best collective set**
20 **of tests for determining the cost-effectiveness of potential DSM/EE projects.⁶ These**
21 **tests and their Manual definitions are:**

⁵ See, e.g., *In the Matter of: the Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company Demand-Side Management for the Review, Modification, and Continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms*, KY PSC Case No. 2007-00319, Attorney General's Comments (October 26, 2007).

⁶ The Manual is available online at: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

- 1 • **The Participant Test:** The Participants Test is the measure of the quantifiable
2 benefits and costs to the customer due to participation in a program. Since
3 many customers do not base their decision to participate in a program entirely
4 on quantifiable variables, this test cannot be a complete measure of the
5 benefits and costs of a program to a customer.⁷

- 6 • **The Ratepayer Impact Measurement Test:** The Ratepayer Impact Measure
7 (RIM) test measures what happens to customer bills or rates due to changes in
8 utility revenues and operating costs caused by the program. Rates will go
9 down if the change in revenues from the program is greater than the change in
10 utility costs. Conversely, rates or bills will go up if revenues collected after
11 program implementation are less than the total costs incurred by the utility in
12 implementing the program. This test indicates the direction and magnitude of
13 the expected change in customer bills or rate levels.⁸

- 14 • **The Total Resource Cost Test:** The Total Resource Cost Test measures the
15 net costs of a demand-side management program as a resource option based
16 on the total costs of the program, including both the participants' and the
17 utility's costs. ... This test represents the combination of the effects of a
18 program on both the customers participating and those not participating in a
19 program. In a sense, it is the summation of the benefit and cost terms in the
20 Participant and the Ratepayer Impact Measure tests, where the revenue (bill)
21 change and the incentive terms intuitively cancel (except for the differences in
22 net and gross savings).⁹

- 23 • **The Program Administrator Cost Test (or "Utility Cost Test"):** The
24 Program Administrator Cost Test measures the net costs of a demand-side
25 management program as a resource option based on the costs incurred by the
26 program administrator (including incentive costs) and excluding any net costs
27 incurred by the participant. The benefits are similar to the TRC [Total
28 Resource Cost] benefits. Costs are defined more narrowly.¹⁰

29 The KPSC has not expressed a preference for one test over another, and has
30 approved programs for KU and LG&E that pass certain tests but do not pass others
31 ("passing" is a value over 1.0). This is consistent with the historical position of the
32 VSCC.¹¹

⁷ Manual at 8.
⁸ Manual at 13.
⁹ Manual at 18.
¹⁰ Manual at 23.
¹¹ See, e.g., *Ex Parte: In re Investigation of conservation and load management programs*, VSCC Case No. PUE900070, 1993 Va. PUC LEXIS 78, Order at *4-*5 (June 28, 1993) ("Staff concluded that no one cost/benefit test provides all of the information necessary for Virginia utilities, the public, and this Commission to evaluate the impact of a DSM program. Each test has strengths and limitations in the information it provides. Therefore, Staff recommended that Virginia utilities be directed to conduct quantitative cost/benefit analyses

1 Though KU/ODP recommends that all the Manual's tests be used when
2 considering DSM/EE programs, KU and LG&E have historically placed additional
3 weight on the Total Resource Cost and Participant Tests; indeed, as shown in KU and
4 LG&E's most recent Joint Integrated Resource Plan, potential DSM/EE programs
5 must first pass the Total Resource Cost and Participant Tests before the utilities will
6 further consider them for possible implementation.¹² KU and LG&E place particular
7 emphasis on the Total Resource Cost Test because it is the most comprehensive
8 indicator of whether a potential DSM/EE program will create net benefits for
9 customers and the utilities. KU and LG&E place special emphasis on the Participant
10 Test because of the voluntary nature of DSM/EE programs in Kentucky; if a potential
11 DSM/EE program will not benefit its participants, it is unlikely to have many
12 participants, and would therefore likely be a waste of resources. For these reasons,
13 KU/ODP recommends that the Commission consider all four of the Manual's tests,
14 but that it place special emphasis on the Total Resource Cost and Participant Tests.

15 **Q. How should the Commission define the terms "achievable," "cost-effective," and**
16 **"be realistically accomplished" as they are used in Chapters 752 and 855 of the**
17 **2009 Acts of Assembly?**

18 **A. The passage in which these terms appear in the relevant chapters of the 2009 Acts of**
19 **Assembly instructs the Commission to "determine[e] achievable, cost-effective**
20 **energy conservation and demand response targets that can realistically be**
21 **accomplished in the Commonwealth through demand-side management portfolios**
22 **administered by each generating electric utility in the Commonwealth." KU/ODP**

from four perspectives: from the perspective of the program participant, the nonparticipant, the utility, and all ratepayers. All the tests identified above, except the Societal Test, provide information that can collectively contribute to a broad understanding of the impact of a particular program.")

1 believes that these terms, taken together, require the Commission to consider all of
2 the various constraints concerning potential DSM/EE programs when recommending
3 energy conservation and demand response targets for each affected utility. These
4 constraints include the time required to implement DSM/EE programs, physical and
5 resource constraints associated with such implementation, the costs of various
6 DSM/EE programs, whether certain programs will be voluntary or mandatory to
7 customers, and the benefits different programs are likely to achieve. For example, a
8 residential load control device program may prove to be quite cost-effective and
9 quick and easy to implement in a service territory dominated by compact residential
10 neighborhoods with flat terrain; conversely, rural and hilly service territories likely
11 would require great time and expense to implement a similar program, and likely
12 would not ultimately be cost-effective. In view of this, KU/ODP respectfully submits
13 that this mix of considerations (as well as others) should result in DSM/EE targets
14 tailored to each utility's particular circumstances and constraints.

15 **Q. How should the Commission determine the "public interest" in preparing a**
16 **"cost-benefit analysis of a demand-side management program"?**

17 **A.** The Manual's Total Resource Cost Test attempts to capture all of the costs and
18 benefits to utility customers (both those who participate in a program and those who
19 do not) in its cost-effectiveness measure. KU/ODP believes it is an appropriate
20 means of determining whether a particular DSM/EE program is in the public interest.

21 **Q. What is the potential impact of the generating electric utility's demand-side**
22 **management program on economic development in the Commonwealth?**

¹² *In the Matter of: the 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, KY PSC Case No. 2008-00148, 2008 IRP at 8-116 (April 21, 2008).*

1 A. If truly cost-effective DSM/EE programs are implemented in the Commonwealth,
2 rates for all ratepayers (including those who do not participate in the programs)
3 theoretically should be lower than they otherwise would have been due to capacity
4 cost avoidance. Such relatively reduced rates, in addition to being able to offer
5 customers DSM/EE programs that may allow them to reduce further their own
6 electricity bills, should help stimulate economic development in the Commonwealth
7 over time.

8 Q. **What is “the range of consumption and peak load reductions that are potentially**
9 **achievable by each generating electric utility”?**

10 A. The answer to the question of what consumption and peak load reductions are
11 “potentially achievable” by a given electric utility must be constrained by the
12 considerations addressed in my answer to the question above concerning the terms
13 “achievable,” “cost-effective,” and “be realistically accomplished”; the answer to the
14 question absent those considerations is that it is “potentially achievable” to realize
15 consumption and peak load reductions from 0% to 100% if time, customer choice,
16 and resources are no object.

17 More reasonably, stated in Table 2 above are the consumption and peak load
18 reductions KU and LG&E project they will achieve in Kentucky through the
19 DSM/EE programs they have in place there. (Those Kentucky reductions benefit
20 KU/ODP’s customers; insofar as KU can avoid capacity costs, KU/ODP’s customers
21 benefit as well.) As I stated earlier in this testimony concerning Table 2, KU and
22 LG&E project a Kentucky consumption reduction of 1.2% during the period 2008-
23 2014 due to their DSM/EE programs, as well as a net capacity avoidance of 303 MW

1 by 2014, which is in addition to the over 127 MW capacity avoidance KU/LG&E's
2 DSM/EE programs achieved as of 2007.¹³

3 It is not possible to know with certainty whether similar results (scaled for
4 KU/ODP's smaller customer base) are achievable in Virginia; however, KU/ODP
5 implicitly assumed for the sake of simplicity and speed that similar results could be
6 achieved in Virginia and scaled to meet various load and consumption reduction
7 targets in its responses to the Interrogatories and Requests for Production of
8 Documents by the Staff of the State Corporation Commission, dated May 22, 2009.
9 These projected results may not be achievable, however, if participation in DSM/EE
10 programs are made voluntary in Virginia. KU and LG&E have deployed DSM/EE
11 programs in Kentucky for a number of years, yet the utilities project that there will be
12 only a 1.2% net reduction in their Kentucky customers' energy consumption, largely
13 because participation in DSM/EE programs is voluntary in Kentucky. KU and LG&E
14 therefore believe that achieving energy savings of up to 20% will almost certainly
15 require customers' mandatory participation in DSM/EE programs.

16 **Q. What is the "range of costs that consumers would pay to achieve those**
17 **reductions, and the range of financial benefits or savings that could be realized if**
18 **the targets were met over a 15 -year period"?**

19 **A.** Concerning the range of costs, in its responses to the Interrogatories and Requests for
20 Production of Documents by the Staff of the State Corporation Commission, dated
21 May 22, 2009, KU/ODP projected on the basis of KU and LG&E's experience in
22 Kentucky that to achieve a goal for DSM/EE to be 5% of KU/ODP's forecasted
23 energy throughput in 2024 would cost \$19.3 million, with an estimated rate impact of

¹³ *Id.* at 8-79 (Table 8.3(e)(3)).

1 approximately \$0.030 per kWh for residential customers and \$0.009 per kWh for
2 commercial customers. (These rate impacts include program costs, lost revenues, and
3 a marginal incentive.) To achieve a goal of 20% would cost \$77 million, with an
4 estimated rate impact of approximately \$0.122 per kWh for residential customers and
5 \$0.037 per kWh for commercial customers. By way of comparison, the total
6 residential rate (including fuel costs) KU/ODP is proposing in its currently pending
7 rate proceeding (PUE-2009-00029) is \$0.07564 per kWh.

8 The benefits KU/ODP's customers would receive would be in avoided
9 capacity cost savings for all customers, as well as presumably reduced energy costs
10 for those who participated in DSM/EE programs. As I stated previously in this
11 testimony, KU/ODP's customers are already benefitting from KU and LG&E's
12 DSM/EE programs because of the avoided capacity cost savings KU and LG&E's
13 Kentucky customers have created.

14 **Q. How should the Commission "determine a just and reasonable ratemaking**
15 **methodology to be employed to quantify the cost responsibility of each customer**
16 **class to pay for generating electric utility-administered demand-side**
17 **management programs"?**

18 **A.** KU/ODP believes that it is appropriate for each customer class to bear the cost of
19 Commission-approved cost-effective DSM/EE programs that are available to the
20 class. For example, residential customers should bear the cost of a residential load
21 control program. This would provide an incentive for each residential customer to
22 participate, whereas socializing the costs across rate classes would reduce that
23 incentive and burden other rate classes with the cost of a program in which their
24 member customers could not participate.

1 Q. What "class cost responsibility methods [are] used in other jurisdictions," and
2 "would [it] be in the public interest for the Commonwealth to have a similar
3 policy" to other jurisdictions that permit certain customers to be exempt from
4 participating in and/or paying for a utility's demand-side management
5 programs?

6 A. In Kentucky, the only jurisdiction in which KU/ODP's sister utilities have DSM/EE
7 programs,¹⁴ a rate class pays only for the DSM/EE programs available to it and
8 allows individual industrial customers to opt out of such programs entirely. KRS
9 278.285(3) states:

10 The commission shall assign the cost of demand-side
11 management programs only to the class or classes of customers
12 which benefit from the programs. The commission shall allow
13 individual industrial customers with energy intensive processes
14 to implement cost-effective energy efficiency measures in lieu
15 of measures approved as part of the utility's demand-side
16 management programs if the alternative measures by these
17 customers are not subsidized by other customer classes. Such
18 individual industrial customers shall not be assigned the cost of
19 demand-side management programs.

20 This exemption for industrial customers is an explicit recognition by the Kentucky
21 General Assembly of Kentucky's industrial customers' opposition to DSM/EE
22 programs, and has been in place since Kentucky's DSM/EE law was enacted in 1994.

23 KU/ODP believes the ability for individual customers to opt out of paying for
24 DSM/EE programs available to their respective rate classes is not in the public
25 interest. The ability to opt out, particularly if it is contingent on a customer's
26 showing that it has put in place other sufficient demand control or energy efficiency
27 measures, has the potential to complicate and add cost to the administration of such

¹⁴ LG&E operates only in Kentucky; KU operates in Kentucky and has five residential customers in Tennessee. KU does not offer DSM/EE programs to its five Tennessee customers.

1 programs (including the billing for such programs), particularly for larger rate classes.
2 It is likely for that reason that Kentucky has limited the ability to opt out of DSM/EE
3 programs to industrial customers, of which there are relatively few.

4 **Q. What DSM/EE target does KU/ODP believe the VSCC should recommend for**
5 **KU/ODP?**

6 **A.** KU/ODP believes that the VSCC should recommend in their report that there not be a
7 DSM/EE target for KU/ODP as long as KU and LG&E continue to maintain and
8 expand their DSM/EE programs in Kentucky, which benefit Virginia customers by
9 reducing the need for capacity additions. Though KU/ODP applauds the Virginia
10 General Assembly for requiring this proceeding and will assist the VSCC in gathering
11 the information needed for its report to the Assembly, because of its small Virginia
12 customer base and service territory, KU/ODP believes it likely will not be cost-
13 effective to implement many, if any, of its DSM/EE programs in Virginia. Moreover,
14 KU/ODP projects very slow load growth in its service territory over the next fifteen
15 years (see Table 3 below), negating one of the primary reasons for implementing
16 DSM/EE programs, namely the slowing of load growth.

1

Table 3

ODP Annual Calendar Sales Forecast (MWh)		
Year	2008 Integrated Resource Plan Forecast	Reforecast
2009	972,351	919,252
2010	979,293	926,846
2011	988,773	936,647
2012	996,990	946,517
2013	1,003,732	956,800
2014	1,008,580	964,177
2015	1,011,124	971,728
2016	1,015,198	981,322
2017	1,021,650	990,204
2018	1,029,817	1,001,243
2019	1,038,028	1,011,767
2020	1,046,608	1,022,226
2021	1,054,324	1,030,286
2022	1,063,448	1,040,806
2023	1,071,716	1,051,462

2

3

As shown in Table 5 below, this projected very slow load growth is consistent with the actual load in KU/ODP's service territory over the most recent five years, which has been essentially flat:

4

5

6

Table 5

ODP Annual Sales (MWh)	
Year	Sales
2004	926,284
2005	952,503
2006	910,050
2007	919,457
2008	916,208

7

8

Given that KU/ODP projects that to achieve even a 5% load reduction would increase its residential rates (including fuel costs) by about 40%, and given its small and stable

9

1 customer base and very slow load growth, KU/ODP does not believe it would be
2 cost-effective to establish a DSM/EE target for its service territory.

3 **Q. Does this conclude your testimony?**

4 **A. Yes.**

APPENDIX A

Lonnie E. Bellar
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006

Professional Experience

E.ON U.S.

Vice President, State Regulation and Rates	Aug. 2007 – Present
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

IEEE

Civic Activities

E.ON U.S. Power of One Co-Chair – 2007
Louisville Science Center – Board of Directors – 2008, 2009
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board – 2009



Southern
Environmental
Law Center

201 West Main Street, Suite 14
Charlottesville, VA 22902-5065
434-977-4090
Fax 434-977-1483
SouthernEnvironment.org

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July 31, 2009

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c/o Document Control Center
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Richmond, Virginia 23218-2118

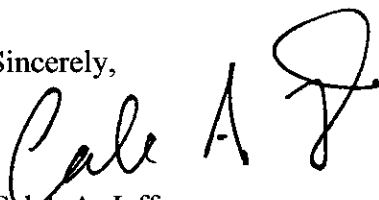
PUE-2009-00023

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,


Caleb A. Jaffe

cc: Parties on Service List
Commission Staff



COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA)
)
At the relation of the)
)
STATE CORPORATION COMMISSION)
)
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.

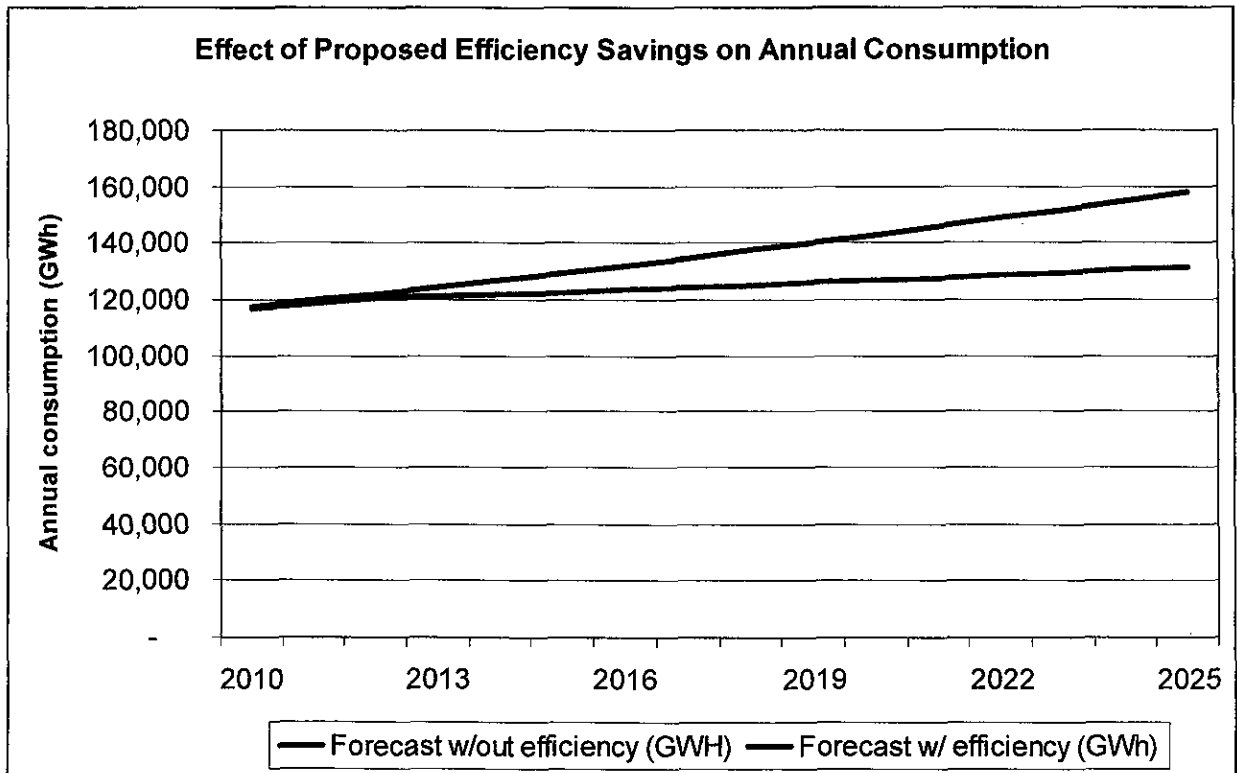
16 **Q: What is the basis for your efficiency target?**

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 Coop, 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 Energy Efficiency Resource Standards Activity				
State	Date Established	Goal	Target End Date	Implied Annual % savings (vs. of total forecast load)
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 2006 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.

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Q. Does the fact that most of these states have been leaders in DSM for a long time and that Virginia has relatively little experience in DSM efforts imply that it is not 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
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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 of Study	Analysis Period (Yrs)	Technical Potential (% of total forecast load)	Economic Potential (% of total forecast load)	Achievable* (% of total forecast load)	Average Annual Achievable** (% of total forecast load)	Source	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 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.

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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Regional Economic Research, Inc.
Seattle City Light**

CONTRIBUTORS

Research Into Action

EVALUATION IN TRANSITION: WORKING IN A COMPETITIVE ENERGY INDUSTRY ENVIRONMENT

1999 INTERNATIONAL ENERGY PROGRAM EVALUATION CONFERENCE

**August 18-20, 1999
Denver, Colorado**

PROCEEDINGS



**The Ninth International
Evaluation Conference**

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%

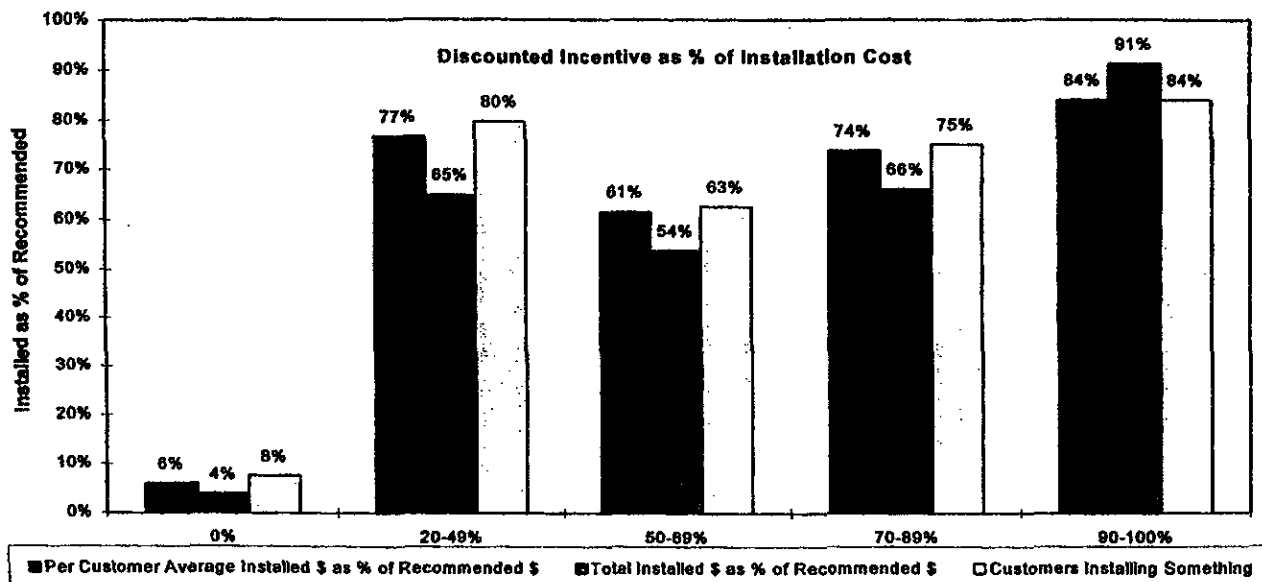


Figure 1. Customer Response to % of Installation Cost Offered

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.

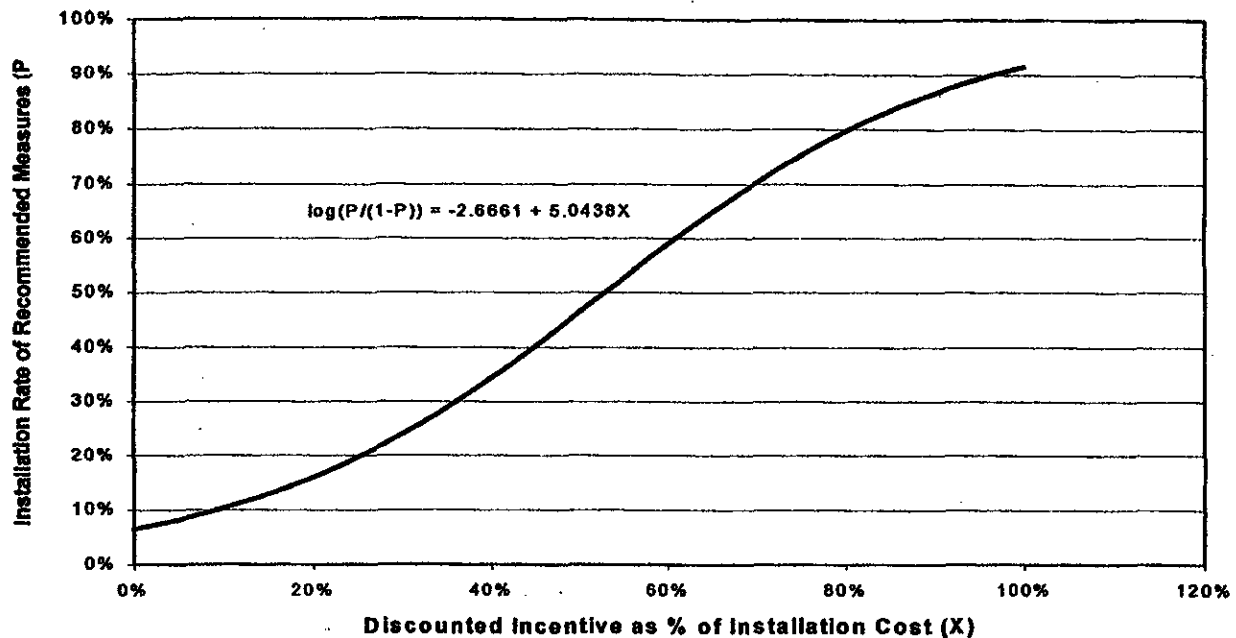


Figure 2. Logistic Curve

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).

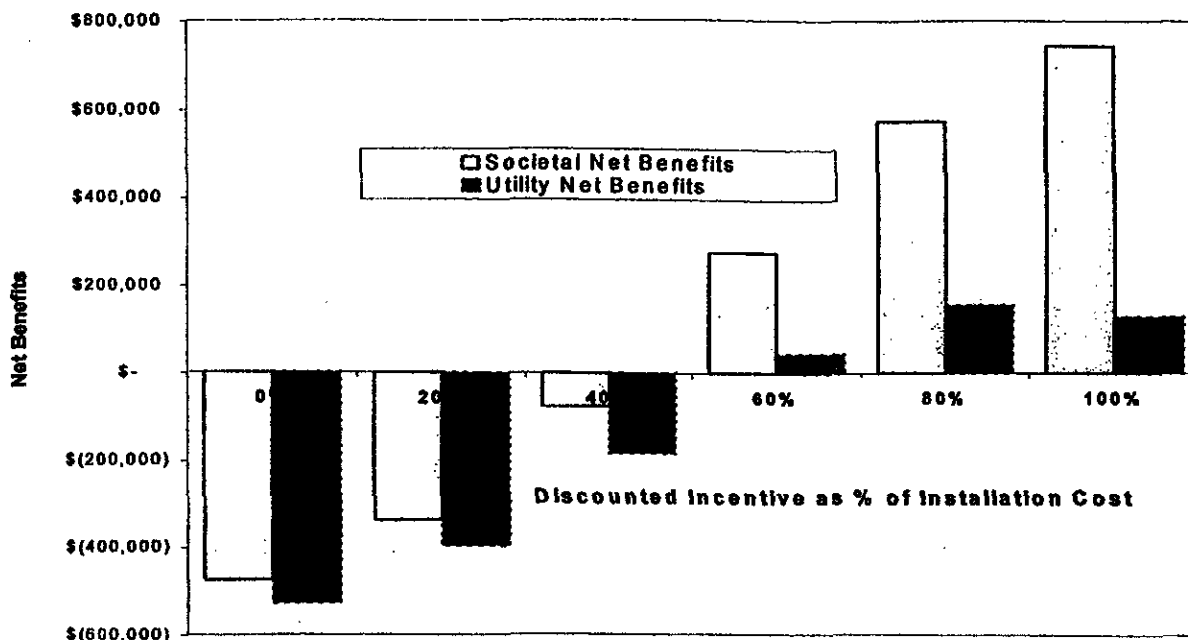


Figure 3. Program Cost-Effectiveness vs. Incentive Level Offered

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; NEPSO 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

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Ex Parte: In the matter of: determining)
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Chapters 752 and 855 of the 2009 Acts of)
the Virginia General Assembly)

Case No. PUE-2009-00023

DIRECT TESTIMONY OF WILLIAM STEINHURST
ON BEHALF OF THE SOUTHERN ENVIRONMENTAL LAW CENTER, ET AL

Filed: July 31, 2009

I. INTRODUCTION

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Q. Please state your name, employer, and present position.

A. My name is William Steinhurst, and I am a Senior Consultant with Synapse Energy Economics (“Synapse”), which is headquartered in Cambridge, Massachusetts. My business address is 45 State Street, #394, Montpelier, Vermont 05602.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of a coalition (“Coalition”) consisting of the Southern Environmental Law Center (“SELC”), Appalachian Voices and the Virginia Chapter of the Sierra Club.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics (“Synapse”) is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your work experience and educational background.

A. I have over twenty-five years’ experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency. I have provided consulting services for various clients, including the Connecticut Office of Consumer Counsel, the Illinois Citizens Utility Board, the California Division of Ratepayer Advocates, the D.C. and Maryland Offices of the Public Advocate, the Delaware Public Utilities Commission, the Regulatory Assistance Project, the National Association of Regulatory Utility Commissioners (“NARUC”), the National Regulatory

1 Research Institute ("NRRI"), American Association of Retired Persons ("AARP"), The
2 Utility Reform Network ("TURN"), the Union of Concerned Scientists, the Northern
3 Forest Council, the Nova Scotia Utility and Review Board, the U.S. EPA, the
4 Conservation Law Foundation, the Sierra Club, the Southern Alliance for Clean Energy,
5 the Oklahoma Sustainability Network, the Natural Resource Defense Council ("NRDC"),
6 Illinois Energy Office, the Massachusetts Executive Office of Energy Resources, the
7 James River Corporation, and the Newfoundland Department of Natural Resources.

8 I hold a B.A. in Physics from Wesleyan University and an M.S. in Statistics and
9 Ph.D. in Mechanical Engineering from the University of Vermont.

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

11 A. I have testified as an expert witness in approximately 30 cases on topics including
12 utility rates and ratemaking policy, prudence reviews, integrated resource planning,
13 demand side management policy and program design, utility financings, regulatory
14 enforcement, green marketing, power purchases, statistical analysis, and decision
15 analysis. I have been a frequent witness in legislative hearings and represented the State
16 of Vermont, the Delaware Public Utilities Commission Staff, and several other groups in
17 numerous collaborative settlement processes addressing energy efficiency, resource
18 planning and distributed resources.

19 I was the lead author or co-author of Vermont's long-term energy plans for 1983,
20 1988, and 1991, as well as the 1998 report *Fueling Vermont's Future: Comprehensive*
21 *Energy Plan and Greenhouse Gas Action Plan*, and also Synapse's study *Portfolio*
22 *Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and*
23 *Efficient Electricity Services to All Retail Customers*. I was recently commissioned by the
24 National Regulatory Research Institute to write *Electricity at a Glance*, a primer on the
25 industry for new public utility commissioners, which included coverage of energy
26 efficiency programs.

27 **Q. Have you previously testified before the Virginia State Corporation Commission**
28 **("The Commission" or "SCC")?**

29 A. No.

1 **Q. What is the purpose of your testimony?**

2 A. In this testimony, I offer recommended answers to a number of the Commission's
3 questions as set out in its Order of April 30, 2009, and address several related issues.

4 **Q. Are you presenting any exhibits to support your testimony?**

5 A. Yes. I have prepared two exhibits to support my testimony. Those supporting
6 exhibits are as follows:

7 Steinhurst Exhibit 1, "Exhibit SELC-WB-1" Comparison of energy efficiency ("EE")
8 and demand response ("DR") impacts for
9 illustrative system load duration curves

10 Steinhurst Exhibit 2, "Exhibit SELC-WB-2" Comparison of bill impacts of EE and DR
11 for illustrative commercial customers

12 **Q. How is your testimony organized?**

13 A. I address, in order, questions No. 2, 3, 4, 5, 8 and 9 from the Commissions Order.
14 I then address the following related issues:

- 15 ○ Lost opportunity resources and cream skimming, and
16 ○ Equity issues relating to energy efficiency programs for hard-to-reach customers.

17 **Q. Please summarize your recommendations.**

18 A. Consistent with my answers to the above listed Commission questions and issues,
19 I recommend that the Commission:

- 20 1. Require that the California PUC 2002 Standard Practice Manual definitions (with the
21 adjustments I describe below or, in the alternative, without those adjustments) be used
22 and that any deviation from them be authorized by the Commission, in advance and
23 after an opportunity for parties to review and comment.
24 2. Reject "relative weighting" of the various cost-benefit tests

- 1 3. Require that the Total Resource Cost (TRC) Test, the Participant Test and the Rate
2 Impact Measure (RIM) Test be applied for the specific purposes for which they are
3 appropriate and only for those purposes
- 4 4. Require three adjustments to the TRC test as described later in my testimony:
 - 5 a. Application of carbon costs to the cost of power
 - 6 b. Application of a 10% upward adjustment to other supply-side costs, and
 - 7 c. Application of a 10% downward adjustment to demand-side management
8 costs.
- 9 5. Adopt, at a minimum, carbon allowance prices with a low-case allowance price of
10 \$15 per ton, a mid- or base-case allowance price of \$30 per ton, and a high-case
11 allowance price of \$78 per ton (all levelized over the period 2013-2030, in 2007
12 dollars)
- 13 6. Correlate the Virginia statute's term "cost-effective" with the *National Action Plan*
14 *for Energy Efficiency's* definition of "economic potential;" the statute's "achievable
15 potential" with the *National Action Plan's* "maximum achievable potential;" and the
16 statute's potential "that can realistically be accomplished" with the *National Action*
17 *Plan's* term "maximum achievable" potential *except* to the extent that specific
18 evidence demonstrates that a specific portion of the maximum achievable potential
19 *cannot* be acquired due to a physical, legal or other practical and irremediable barrier
20 to acquiring some particular cost-effective resource in some particular market
21 segment *other* than budget limitations.
- 22 7. Require that utilities rely on the TRC Test (as adjusted according to this testimony)
23 and *only* the TRC Test in cost-benefit analysis, both for program design and for field
24 implementation
- 25 8. Require that the full costs and risks of supply-side alternatives be reflected in cost-
26 benefit analysis

1 9. Require that utility Demand Side Management (DSM) targets equal the maximum
2 achievable potential, reducing those estimates only on evidence that there is a specific
3 and objectively documented physical, legal or practical barrier to acquiring some
4 particular cost-effective resource in some particular market segment other than a
5 (desired or proposed) budget limitations.

6 10. Allocate utility DSM program costs among all rate classes according to allocation
7 factors that classify those costs as follows:

8 a. Costs for programs that produce energy-related benefits should be allocated
9 using an "energy" allocation factor (e.g. annual kWh by rate class)

10 b. Costs for programs that produce capacity-related benefits should be allocated
11 using a "capacity" allocation factor (e.g. kW of coincident peak by rate class)

12 c. Costs for programs that produce a combination of energy and capacity
13 benefits consistent with average annual supply costs should be allocated using
14 an annual supply cost allocation factor (e.g. annual supply costs by rate class.)

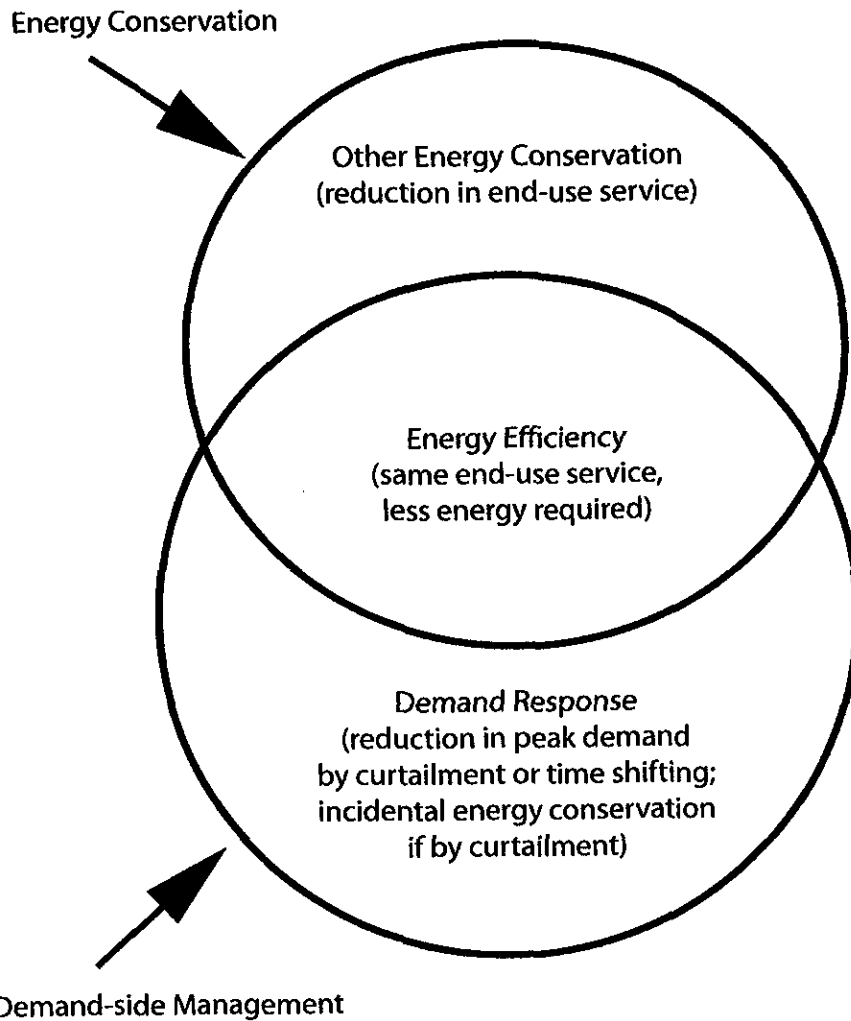
15 11. Require utilities to address programs for limited-income customers and other hard-to-
16 reach customers so as to assure proportionate energy efficiency programs are
17 deployed in those customer groups and, if necessary to fulfill that requirement, allow
18 programs targeted to low-income or other hard-to-reach customers to meet lower
19 threshold cost-effectiveness results than other programs or be enhanced in other ways
20 to ensure that those customers are not left out.

21 **Q. Before turning to the Commission's Questions, please explain your understanding of**
22 **the terms "energy efficiency," "demand response," and "energy conservation."**

23 **A.** Some of the Virginia statutes within the scope of this proceeding use both terms
24 "energy efficiency" and "energy conservation" in various contexts. See, for example,
25 2007 Acts of Assembly Chapter 888 (House Bill 3068) and the identical senate bill, 2007
26 Acts of Assembly Chapter 933 (Senate Bill 1416), Enactment Clause 3 ("... it is in the
27 public interest, and is consistent with the energy policy goals in § 67-102 of the Code of
28 Virginia, to promote cost-effective conservation of energy through fair and effective

1 demand side management, conservation, energy efficiency, and load management
2 programs, including consumer education.”).

3 By “energy conservation,” I mean actions that change residential or commercial
4 arrangements, processes or structures so as to reduce the amount of end use energy
5 required or demanded. This may be accomplished by (1) improving energy efficiency or
6 (2) by simply discouraging the use of energy. An example of the latter would be
7 discouraging the use of electric heating tapes to keep ice from forming on the eaves of
8 houses during the winter, which would simply reduce the amount of end use service
9 (heating of roofs), perhaps at the cost of requiring improved roof construction and
10 insulation. I use “energy efficiency” to mean the type of energy conservation measures or
11 programs that seek to deliver a particular end use service (e.g., lighting, cooling, heating,
12 traction, etc.) in a manner that requires consumption of less electric energy. In addition, I
13 use “demand response” to mean measures or programs intended to reduce demand at the
14 time of peak load; this may be done by curtailing customer usage at certain times and
15 under certain conditions or by shifting that usage to off-peak hours. Lastly, I use the term
16 “demand-side management” or “DSM” to mean measures or programs that *either* deliver
17 energy efficiency or demand response, as defined in this paragraph. Thus, energy
18 efficiency and demand response, together, make up the range of DSM measures, and
19 DSM, in turn, is a subset of energy conservation. The relationship of these four terms is
20 illustrated in Fig. 1, below.



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Fig. 1. Definitions of Energy Conservation and Related Terms

In this testimony I will discuss demand-side management as comprised of energy efficiency and demand response measures or programs, and will be mainly concerned with energy efficiency in the sense of delivering a particular end use service in a manner that requires consumption of less electric energy. At this early stage in the Commission's consideration, I believe it would be most productive to focus on energy efficiency, because utility programs around the country have repeatedly demonstrated huge cost-effective potential for such programs, and because there are numerous important

1 regulatory issues that need to be resolved to enable vigorous and speedy acquisition of
2 energy efficiency resources.¹

3
4 **II. RESPONSES TO COMMISSION QUESTIONS**

5
6 **Commission Question No. 2. What industry-recognized tests should be used in determining**
7 **cost-effective consumption and peak load reductions and what relative weighting should be**
8 **afforded to any test recommended for use by the respondent generating electric utility?**

9
10 **Q. What industry-recognized tests should be used in determining cost-effective**
11 **consumption and peak load reductions?**

12 **A.** For most purposes, the Total Resource Cost (“TRC”) Test is the only one on
13 which the Commission should rely. Neither the Participant Test nor the RIM Test should
14 be given any weight whatsoever for the purposes of determining whether a given measure
15 or program design is cost effective or for field screening, goal setting, program
16 evaluation, or evaluating the cost-effectiveness of the overall portfolio of a utility’s DSM
17 programs. There are other auxiliary purposes for which the Participant and RIM Tests
18 may be used.

19 The costs and benefits of energy efficiency are, in some ways, qualitatively
20 different from those of supply-side resources, and have different implications for the
21 various parties. As a result, a number of cost-benefit tests have been devised to consider
22 efficiency costs and benefits from different perspectives. There are several industry-
23 recognized tests for determining whether a particular measure or program that delivers
24 energy efficiency resources or demand response (together, DSM) is cost-effective.² The

¹ I do not intend to diminish the potential value to the Commonwealth of that third category of “energy conservation,” i.e., energy conservation in the sense of changing residential or commercial arrangements, processes or structures so as to reduce the amount of end use service required or demanded; that type of energy conservation can be socially valuable. There is certainly nothing in the statutes discussed herein that would prevent the Commission from considering or requiring utility programs to promote energy conservation in that sense.

² See the immediately preceding question and answer for definitions of energy efficiency, demand response and demand-side management.

1 most authoritative source for the definitions of these tests is the California PUC
2 Standard Practice Manual, 2002 edition.³

3 **Q. Please explain the nature of those tests and the differences between them.**

4 **A.** Certainly. I will give a brief explanation of each along with a numerical example.⁴

5 • The Participant Test considers whether the customer receiving a DSM measure
6 will save more money than her share of the measure's cost. For example, consider
7 energy efficient light bulbs as a DSM measure. Assume a package of energy
8 efficient light bulbs costs \$10 retail and are eligible for a \$5 rebate from the local
9 utility. A customer who purchases them would pay an initial net purchase price of
10 \$5. Further assume that the bulbs will save the customer at least \$5 in retail
11 power costs over their life. Based upon those assumptions, that DSM measure
12 would pass the Participant Test because the benefits to the Participant, i.e. savings
13 of at least \$5 in retail power costs, equal or exceed the \$5 net purchase price paid
14 by the Participant.

15 • The TRC Test considers whether the cash savings due to a measure are greater
16 than the cash costs of that measure, regardless of who pays or benefits from it.
17 Returning to the previous example, a package of efficient light bulbs that costs
18 \$10. Assume that these bulbs will enable the utility to avoid at least \$15 in
19 electricity supply costs over their life. (The amount the utility avoids exceeds the
20 amount the bulb-buying customer avoids because the utility avoids the marginal
21 cost of generation including new power plants, while the customer avoids the
22 embedded or average cost of existing generation). From a resource planning

³ California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, CA PUC, July 2002. Available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF. ("California Manual")

⁴ Two other commonly referenced tests are the Energy System Test (generally equivalent to the Utility Cost Test or Program Administrator Test) and the Societal Test. The Energy System Test considers whether the direct cost of providing electricity (or natural gas, in the case of gas utilities) is increased or decreased by a given measure. It is less widely used than the TRC Test because it has a more narrow focus. The Societal Test considers all the costs and benefits of efficiency to all of society, including more difficult to quantify benefits such as environmental benefits. It may be viewed as an extension of the TRC Test and has theoretical attraction, although it can be difficult to implement. Later in my testimony, I recommend certain modifications to the TRC.

1 perspective, the net cash savings due to installation of the bulbs would be \$5, i.e.,
2 \$15 minus \$10. The measure would pass the TRC Test.⁵

3 • Finally, the Ratepayer Impact Measure (RIM) Test considers the impact on
4 ratepayers who do not participate in a program. Using the same example, suppose
5 that participants installed enough energy efficient light bulbs to reduce the
6 utility's total sales by 1%, but that avoidable energy costs were only ½ of the
7 utility revenue requirement.⁶ Then, putting aside the cost of the efficient light
8 bulb program, the utility's average rates would go down ½%. If the cost of the
9 program (rebates on the bulbs, marketing, administration, etc.) exceeded that
10 savings, the program would fail the RIM Test. Such effects are often small
11 enough that even minor efficiency improvements put customers ahead.

12 **Q. Should the Commission provide the utilities with explicit guidance as to what tests**
13 **to use and for what purposes?**

14 A. Yes, it would be very useful for the Commission to do so. In order to avoid
15 confusion and error, and to assist the utilities in their work, the Commission should
16 specify and define acceptable cost-benefit tests for DSM measure and program screening
17 and evaluation. Appalachian Power Company ("APCO") witness Castle agrees that the
18 Commission should do so, although as I will explain, I take a different position on what
19 guidance the Commission should issue.⁷

20 Virginia Electric and Power Company ("Dominion"), however, appears to favor
21 an ultimately subjective approach that looks at multiple tests in conjunction with each
22 other.⁸ To avoid confusion, delay and lack of accountability, I believe that it is essential

⁵ This explanation of the TRC Test is essentially similar to the one in the *Virginia Energy Plan*, which states, "This test "indicates whether an energy-efficiency measure or program has a cost per lifetime-kilowatt-hour-saved less than the avoided cost of electric generation, transmission, and distribution." Department of Mines, Minerals and Energy. The Virginia Energy Plan (2007), at 61.

⁶ The revenue requirement for a given amount of service is the amount of money that would be allowed in rates, all other things being equal, for the provision of that service. In broad terms, it includes power costs, transmission and distribution ("T&D") costs, administration and general ("A&G") costs (all of which may include depreciation), taxes, and return on capital (debt service, preferred dividends, and return on equity). Some of those costs are avoidable in the short term by reducing load, some are not.

⁷ Direct Testimony of William K. Castle on behalf of Appalachian Power Company, June 30, 2009, generally, e.g., at 2. Mr. Castle goes on to recommend, as I do, adoption of the TRC Test and consideration of other tests by the Commission "in order to shape program design." Castle testimony at 13.

⁸ Direct Testimony of Shannon L Venable on behalf of Virginia Electric and Power Company, June 30, 2009, p. 8.

1 for the Commission to be clear and precise and to order that the TRC Test, with my
2 proposed adjustments, is *the* determinant of cost-effectiveness to be used for utility DSM
3 measures and programs.

4 **Q. Don't certain authorities speak of using multiple tests in conjunction?**

5 A. I cannot speak about all such authorities, but some credible authorities might
6 appear to be recommending use of multiple tests. However, that is a superficial
7 understanding.

8 There are passages where the most authoritative sources might seem to
9 recommend reliance on multiple tests. One authority, the *California Standard Practice*
10 *Manual*, states:

11 The tests set forth in this manual are not intended to be used individually or in
12 isolation. The results of tests that measure efficiency, such as the Total Resource
13 Cost Test, the Societal Test, and the Program Administrator Cost Test, must be
14 compared not only to each other but also to the Ratepayer Impact Measure Test.⁹

15 Another, the *Guide to Resource Planning with Energy Efficiency*, a REPORT OF the
16 *National Action Plan for Energy Efficiency* ("NAPEE" or "*National Action Plan*") states,
17 "A common misperception is that there is a single best perspective for evaluation of cost-
18 effectiveness."¹⁰

19 However, neither of those authorities should be understood as recommending that
20 the RIM Test or the Participant Test be used for determining the cost-effectiveness of EE
21 measures and programs. The *National Action Plan's* Guide, for example, goes on to say,
22 "Each test is useful and accurate, but the results of each test are intended to answer a
23 different set of questions." The *Guide* goes on to state, "The TRC test, which measures
24 the regional net benefits, is the appropriate cost test from a regulatory perspective. All
25 energy efficiency that passes the TRC will reduce the total costs of energy in a region."¹¹

26 Another *National Action Plan* report explains this more bluntly:

27 If used, [the RIM Test] is typically a secondary consideration test done on a
28 portfolio basis to evaluate relative impacts of the overall energy efficiency

⁹ *California Manual*, p. 6.

¹⁰ Department of Energy and Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency: A Resource of the National Action Plan for Energy Efficiency*. November 2007, p. 5-2. Available at http://www.epa.gov/cleanenergy/documents/resource_planning.pdf.

¹¹ *Guide* at 5-3.

1 program on rates. The results will provide a high-level understanding of the likely
2 pressure on rates attributable to the energy efficiency portfolio. A RIM value
3 below 1.0 can be acceptable if a state chooses to accept the rate effect in exchange
4 for resource and other benefits. Efficiency measures with a RIM value below 1.0
5 can nevertheless represent the least-cost resource for a utility, depending on the
6 time period and long-term fixed costs included in the avoided costs.¹²

7 As to the California *Manual*, it also states, “Issues related to the precise weighting
8 of each test relative to other tests and to developing formulas for the definitive balancing
9 of perspectives are *outside the scope of this manual*.” [emphasis added]¹³ From my
10 involvement in litigation before the California PUC, it is my experience that for the
11 purposes of determining whether a given measure or program design is cost effective or
12 for field screening, goal setting, program evaluation, or evaluating the cost-effectiveness
13 of the overall portfolio of a utility’s DSM programs, the RIM Test and the Participant
14 Test are not “balanced” with the TRC Test.

15 Thus, in sum, it is misleading to think that credible authorities mentioned here
16 recommend using the RIM Test or the Participant Test to determine whether a given
17 measure or program design is cost effective or for field screening, goal setting, program
18 evaluation, or evaluating the cost-effectiveness of the overall portfolio of a utility’s DSM
19 programs. To the extent other authorities may choose to do so, they are in error and are in
20 violation of the principle of least cost planning.

21 **Q. What test definitions and relative weighting do you recommend the Commission**
22 **adopt and require be used by the utilities?**

23 A. I recommend that the Commission require that the California PUC 2002 Standard
24 Practice Manual definitions (with the adjustments I describe below or, in the alternative,
25 without those adjustments) be used, and that any deviation from them be authorized by
26 the Commission, in advance and after an opportunity for parties to review and comment.
27 There should be no “relative weighting” of the various tests at all. Rather, the TRC Test,
28 the Participant Test and the RIM Test should be applied for the specific purposes for

¹² Department of Energy and Environmental Protection Agency. Understanding Cost-Effectiveness of Energy Efficiency Programs, November 2008, at 5-2. Available at <http://www.epa.gov/cleanenergy/documents/cost-effectiveness.pdf>.

¹³ California *Manual* at 6.

1 which they are appropriate and only for those purposes. Simply put, each test is fit for
2 certain purposes and not for others.

3 It is absolutely crucial to understand from the outset that, for most purposes, the
4 TRC Test is the *only* one on which the Commission should rely. Those purposes include
5 measure and program screening in both program design and program implementation, as
6 well as goal setting, program evaluation, and evaluating the cost-effectiveness of the
7 overall portfolio of a utility's DSM programs.¹⁴ Two other tests, the Participant Test and
8 the Rate Payer Impact ("RIM") Test may be given weight in the Commission's
9 deliberations, but only for certain limited purposes.

10 Neither the Participant Test nor the RIM Test should be given any weight
11 whatsoever for the purposes of determining whether a given measure or program design
12 is cost effective or for field screening, goal setting, program evaluation, or evaluating the
13 cost-effectiveness of the overall portfolio of a utility's DSM programs. As explained in
14 more detail below, the RIM Test excludes any resource that would increase per-unit rates
15 even if that resource reduces the cost of service or has net benefits to society. Therefore, I
16 conclude that the RIM Test has no place as a tool in cost-effectiveness screening or
17 identifying least-cost resource portfolios. The Participant Test can be useful in choosing
18 marketing techniques for DSM, such as setting rebate levels, but too, has no place as a
19 tool in cost-effectiveness screening or for identifying least-cost resource portfolios.

20 **Q. You have recommended the Commission require use of the TRC test for screening**
21 **DSM resources and mentioned that you recommend certain adjustments to that test.**
22 **Please explain those recommended adjustments.**

23 **A.** I recommend three adjustments to the TRC test.

¹⁴ DSM program design and program implementation both include a task called "screening." In program design, candidate DSM measures and whole programs are "screened" to determine whether or not they pass the relevant cost-effectiveness test. Two general classes of DSM measures are treated differently in program implementation. Some are screened for cost-effectiveness in the program design stage and found to be broadly or universally cost-effective, so they are made available during implementation without further analysis. An example might be rebates for compact fluorescent light bulbs. Others are determined during program design to be cost-effective in some circumstances, but not others, so they are rescreened "in the field" to see if they are cost-effective for a specific customer or facility. An example might be an upgrade to a more efficient chiller in an office building, where cost-effectiveness might depend on the particulars of the structure and its occupation pattern. The last of these situations is commonly called "field screening." To be clear, only the TRC Test should be used to determine cost-effectiveness either in screening for program design or in field screening.

1 The first has to do with the inclusion of values for carbon costs in the avoided cost
2 of energy and capacity to be used in design, field screening and evaluation of utility
3 energy efficiency programs and in goal setting. Methods for monetizing carbon costs are
4 in flux, but a value of zero is clearly wrong. Below in this testimony, I recommend a
5 specific range of numeric values for use in that adjustment at this time. This adjustment
6 would increase the avoided costs used in the TRC Test and make somewhat more DSM
7 programs cost-effective.

8 Second, I recommend an adder of 10% to the avoided cost of transmission and
9 distribution, reserves and ancillary services within the TRC calculation to represent the
10 non-energy benefits of avoiding those requirements, such as land use impacts. This
11 adjustment would also increase the avoided costs used in the TRC Test and make
12 somewhat more DSM programs cost-effective.

13 I recommend that the Commission direct that these first two adjustments be
14 applied in addition to the other quantifiable benefits from DSM, and that they be used
15 when calculating TRC values for specific DSM measures and programs in both program
16 design and field screening, as well as for goal setting, for program evaluation and for
17 evaluating the cost effectiveness of the overall portfolio of a utility's DSM programs.
18 This is comparable to the way external costs of supply-side resources are recognized, for
19 example, in Vermont.¹⁵

20 Third, I recommend that the costs of DSM measures and programs be reduced by
21 10% prior to being used in the TRC calculation to reflect their lower risk compared to
22 supply-side alternatives. Paralleling my first adjustment, I recommend that the
23 Commission direct that this third adjustment be applied as a reduction to the sum of the
24 costs of DSM, and that it be used when calculating TRC values for specific DSM
25 measures and programs in both program design and field screening, as well as for goal

¹⁵ This percentage adder approach to factoring environmental costs into resource evaluation was widely used in the 1990s and usually applied equally to avoided costs of generation and T&D. See, for example, Vt. Public Service Board Final Order in Docket 5270, 1990; S. Stoff, J. Eto and S. Kito, *DSM Shareholder Incentives: Current Designs and Economic Theory*, Lawrence Berkeley Laboratories, 1995. More recently in the western states, the emphasis for generation externalities has been on pricing carbon emissions, but the percentage adder approach remains valid for non-generation avoided costs that impose external costs on society in areas of land use, habitat intrusion, scenic and tourism effect, and so on, as well as the costs of unanticipated increases in future fuel prices.

1 setting, for program evaluation and for evaluating the cost-effectiveness of the overall
2 portfolio of a utility's DSM programs. Unlike the first two recommended adjustments,
3 this adjustment would not change the avoided costs used in the TRC Test, but would
4 lower the cost of the DSM measures for the purpose of that test; however, it would also
5 make somewhat more DSM cost-effective.

6
7 **Q. What is the relevance of carbon regulation to this proceeding?**

8 A. The cost of using fossil fuel for power generation will likely rise significantly as
9 the federal government moves to constrain carbon-heavy power generation. Large-scale
10 energy efficiency will help reduce carbon emission compliance costs. The Virginia
11 Energy Plan observed that managing the transition to a carbon-constrained economy will
12 require that energy efficiency on a large scale be undertaken first as the only negative-
13 cost strategy for dealing with climate change ("The potential for carbon regulation . . .
14 creates a risk that Virginia's low-cost generation resources may cost more in the future.
15 Adding energy efficiency and conservation to the mix reduces this risk. . . . Utilities and
16 their consumers face less technical and financial risk if there is less need to construct new
17 facilities." *Va. Energy Plan* at 62.

18 **Q. Can you give us some examples of CO₂ allowance prices used in utility resource
19 planning as would be required under your first proposed adjustment to the TRC
20 test?**

21 A. Yes. In its 2005 Integrated Resource Plan, Avista used a range from \$7 to \$25/ton
22 for the 2010 planning year and from \$15 and \$62/ton for the 2023 planning year. Portland
23 General Electric and Pacificorp adopted a range of \$0 to \$55/ton beginning in 2003 and
24 2004, respectively. Idaho Power adopted a range of \$0 to \$61/ton starting in 2008.
25 Northwest Energy adopted a range of \$15 to \$41/ton starting in 2005. (I would not
26 consider \$0 to be a credible low case value at this time.) Those values are all in 2005
27 dollars.¹⁶

¹⁶ David Schlissel, Lucy Johnston, Bruce Biewald, David White, Ezra Hausman, Chris James, and Jeremy Fisher, *Synapse 2008 CO₂ Price Forecasts*, at 21. Available at <http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf>

1 The California PUC requires that regulated utility IRPs include carbon adder of
2 \$8/ton CO₂, escalating at 5% per year as of 2005.¹⁷ The Oregon PUC has adopted a range
3 from \$0 to about \$85/ton (levelized 2013-2030 in 2007 dollars). Other PUCs have
4 adopted ranges from the teens to \$35-\$45/ton (also levelized 2013-2030 in 2007
5 dollars).¹⁸

6 Various analyses of a number of proposed federal climate change laws indicate
7 early year costs of nearly \$10 to over \$60/ton, with the 2018 range going from just over
8 \$10 to about \$90/ton with all the analyses rising steadily thereafter (in 2007 dollars).¹⁹
9 The U.S. Department of Energy has recently issued estimates with a low-range value of
10 \$2/ton, a mid-range value of \$33/ton and a high-range value of \$80/ton, escalating at 3%
11 per year.²⁰ (I would not consider \$2/ton to be a credible low case value at this time.)

12 **Q. Do you have recommendations for what CO₂ allowance prices the utilities should**
13 **use for planning utility energy efficiency programs and goal setting ?**

14 A. Yes. I recommend that, at a minimum, the Commission require the use of
15 allowance prices with a low-case allowance price of \$15 per ton, a mid- or base-case
16 allowance price of \$30 per ton, and a high-case allowance price of \$78 per ton (all
17 levelized over the period 2013-2030, in 2007 dollars). I believe that a reasonable figure
18 for the *long-run* marginal cost of carbon emissions is around \$80 (in 2008 dollars, or
19 about \$78 in 2007 dollars) and recommend that the Commission require high-case
20 analysis reflecting that price be analyzed and considered in permanent goal setting.

21 I believe the recommended mid-range allowance price forecast is close to what
22 greenhouse gas allowances will initially sell for in a federal program and much more
23 realistically reflects current expectation than the utility witnesses' assumptions would,
24 even if they had allowed those prices to influence their proposed goals. At the same time,
25 I believe using unrealistically high allowance prices, like those included in the utilities'

¹⁷ CPUC Decision 05-04-024

¹⁸ Schlissel, et al., op. cit.

¹⁹ Ibid., Fig. 5.

²⁰ U.S. DOE, *Energy Conservation Program: Energy Conservation Standards and Test Procedures for General Service Fluorescent Lamps and Incandescent Reflector Lamps*, pp. 14-15. Available at <http://www.epa.gov/fedrgstr/epa-impact/2009/july/day-14/i15710b.htm>

1 high price assumptions, do a disservice by overstating the potential costs of a federal
2 program.

3 **Q. Regarding your third proposed adjustment to the TRC test, please explain your**
4 **basis for recommending a 10% reduction to DSM program and measure costs in the**
5 **TRC test to represent non-energy benefits of DSM in measure and program**
6 **screening and evaluation?**

7 A. I discuss the risk avoidance benefits and hedging benefits of utility energy
8 efficiency programs relative to supply-side resources elsewhere in this testimony. Here, I
9 will discuss one specific aspect of this matter.

10 DSM programs offer immense risk reduction benefits for ratepayers and utility
11 stockholders, alike, when compared to supply-side resources, even when implementation
12 is not 100% successful. For example, energy efficiency can help reduce the risks
13 associated with fossil fuels and their inherently unstable price and supply characteristics
14 and avoid the costs of unanticipated increases in future fuel prices. It is well understood
15 that fuel diversity is desirable, particularly when it reduces rate sensitivity to fuel costs.
16 Generally, energy efficiency has zero sensitivity to fuel costs making it superior to
17 generation in that regard.

18 Energy efficiency can also reduce the risks associated with environmental
19 impacts, by reducing a utility's environmental impacts and helping utilities and their
20 ratepayers avoid the hard to predict costs of complying with potential future
21 environmental regulations, such as CO₂ regulation.²¹ Of course, energy efficiency also
22 reduces the risks associated with regulatory, liability and other costs associated with other
23 environmental and health effects, such as those from mercury and other hazardous air
24 pollutants, as well as the risks to the Commonwealth's economy from potential ozone
25 non-attainment problems. Energy efficiency can improve the overall reliability of the
26 electricity system by reducing peak demand at those times when reliability is most at risk
27 and by slowing the rate of growth of electricity peak and energy demands and giving
28 utilities more time and flexibility to respond to changing market conditions, while

²¹ The U.S. EIA *Annual Energy Outlook* for 2009 and, as mentioned therein, issuances by Citibank, JPMorgan Chase, and Morgan Stanley all express new or increased concern over the impact of CO₂ regulation on the industry. Available at [http://www.eia.doe.gov/oiaf/aeo/pdf/0383\(2009\).pdf](http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf)

1 moderating the “boom-and-bust” effect of competitive market forces on generation
2 supply.²²

3 **Q. How is it that energy efficiency is less risky than supply-side alternatives?**

4 A. Energy efficiency is generally less risky than supply-side alternatives because
5 DSM programs are modular and easily adjustable as circumstances change. Plus, each
6 measure installed delivers benefits beginning immediately, unlike power plants that
7 deliver no benefits at all unless and until they are completely built; uncertainties in load
8 forecasts, capital costs of new generation, permitting delays and so on are types of
9 planning risk that burden supply-side options but not DSM resources.

10 Utility Respondent witnesses make much of their lack of certainty as to the
11 amount of DSM they can actually harvest, but make no effort in their testimony to
12 compare those uncertainties to the many risks, financial and otherwise, that generation
13 alternatives carry with them.²³ The important point here is that any difficulties that arise
14 in DSM program delivery can be identified, addressed and remedied in as little as one
15 calendar quarter, while a problem that crops up in the construction or operation of a new,
16 large-scale fossil fueled or nuclear power plant can take a decade to surface and be
17 irretrievable once identified.

18 I consider a 10% downward adjustment to DSM costs a reasonable proxy for the
19 value of avoiding the cost of those risks.²⁴ Ten percent is a commonly use contingency

²² Steven Nadel, Fred Gordon and Chris Neme, *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*: ACEEE 2000, <http://www.aceee.org/pubs/u008.htm>; Regulatory Assistance Project, *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, prepared for the National Association of Regulatory Utility Commissioners, June 2001. Available at <http://www.raponline.org/pubs/general/effreli.pdf>.

²³ See, for example, Venable testimony at 12, 14, 16-18; Direct Testimony of Barry L. Thomas on behalf of Appalachian Power Company, June 30, 2009, at 7; Direct Testimony of Fred D. Nichols II on behalf of Appalachian Power Company, June 30, 2009, at 5-6.

²⁴ There are various other ways of treating these risk reduction benefits in resource selection. To minimize the regulatory burden, I have proposed the simplest of those: application of a percentage discount to the cost of DSM. That is the approach utilized in Vermont since 1990. Vt. PSB Final Order in Docket 5270. More complicated methods for addressing this issue are widely used by firms of all kinds in their internal planning. Roschelle, A., Steinhurst, W., Peterson, P., and Biewald, B. (2004). “Long Term Power Contracts: The Art of the Deal,” *Public Utilities Fortnightly* (August), 56-74. One of those methods is the use of risk-adjusted discount rates. See, for example, Bolinger, M., and Ryan Wiser, R., *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, LBNL-58450, available at <http://eetd.lbl.gov/EA/EMP>. (“Increasingly, analysts are calling attention to the benefits of renewable energy as a hedge against electricity sector risks. In particular, renewable energy may be viewed as a valuable contributor to a generation portfolio due to its ability to mitigate

1 reserve for major construction projects and, so, is a reasonable proxy for at least one of
2 the many risks borne by supply-side resources and not by DSM programs. (Some
3 generation-related projects, such as nuclear decommissioning projects are planned with
4 contingency factors of 25% or more.)

5 **Q. Earlier in your testimony, you criticized the RIM Test. Please explain in more detail**
6 **why you recommend against its use in DSM program design or implementation and**
7 **related activities.**

8 A. The RIM Test has significant flaws, any one of which should preclude its use in
9 deciding whether a given measure or program is cost-effective. Some of those flaws
10 include:

- 11 1. , Perhaps most importantly, the RIM Test simply will not result in the lowest cost
12 to society.
- 13 2. Rate impacts and lost revenues represent a transfer payment between non-
14 participants and participants. Consequently, they are not a new cost, and should
15 not be applied as such in screening a new energy efficiency resource. Rate
16 impacts and lost revenues may create equity issues between customers. However,
17 these equity issues should not be addressed through the screening of efficiency
18 programs, but through other means, as described below.
- 19 3. Screening efficiency programs with the RIM Test is inconsistent with the way that
20 supply-side resources are screened and fails to create a level playing field for the
21 consideration of supply- and demand-side resources. There are many instances
22 where utilities invest in new power plants or transmission and distribution
23 facilities in order to meet the needs of a subset of customers, (e.g., new residential
24 divisions, an expanding industrial base, geographically-based upgrades, customers
25 with high reliability requirements). These supply-side resources are not evaluated

natural gas price risk and the risk of future environmental regulations, most notably the risk of future carbon regulation (see, e.g., Wiser et al., 2005; Bolinger et al. 2005; Wiser et al. 2004; Awerbuch 1993, 2003; Hoff 1997; Cavanagh et al. 1993).”) The complex Monte Carlo analyses that form the basis of the Northwest Power and Conservation Council discussed elsewhere in this testimony are another approach to the same problem. These methods have much to recommend in terms of objectivity and transparency and have been used in Washington, Nevada, California, Idaho and other jurisdictions, but their adoption would require the Commission to first undertake a lengthy proceeding to determine the risk tolerance of ratepayers, which is one reason I have recommended a streamlined approach.

1 on the basis of their equity effects, nor are the “non-participants” seen as cross-
2 subsidizing the “participants.” Energy efficiency resources should not be subject
3 to different screening criteria than supply-side resources.

4 4. Consumers, in the end, are more affected by the size of their electric bills (the
5 product of rates and usage) than by the rates alone. The RIM Test does not
6 provide any information about what happens to electric bills as a result of
7 program implementation.

8 5. A strict application of the RIM Test can result in the rejection of large amounts of
9 energy savings and the opportunity for large reductions in many customers’ bills
10 in order to avoid *de minimus* impacts on non-participants’ bills. From a public
11 policy perspective, such a trade-off is illogical and inappropriate.

12 **Q. Are there any effects of DSM cost-benefit testing related to rates that the**
13 **Commission should take into account?**

14 A. Yes. While the RIM Test should not be relied on to screen energy efficiency
15 programs, there are two rate effect issues that may be of concern to ratepayers and the
16 Commission: (1) the importance of rate impacts of any size, and (2) concerns about the
17 effects of efficiency program on non-participants.

18 The first of those issues should be addressed by:

- 19
- 20 1. evaluating the package of energy efficiency programs as a whole, including those
21 programs that might increase rates and those that might decrease rates.
 - 22 2. including all avoided costs in the rate impact estimate: avoided energy, avoided
23 capacity, and avoided T&D. Also, the potential for increased off-system sales
24 should be considered.
 - 25 3. quantifying the potential rate impacts over time. Efficiency programs will have
26 lower (and, possibly, downward) rate impacts in later years. This latter effect is
27 particularly likely if DSM is used aggressively enough to mitigate or defer the
28 need for investments in new high cost generation.
 - 29 4. presenting the rate impacts in terms of percent increase, per year, by sector. This
30 is necessary to make a meaningful assessment of the impacts on customers. These

1 rate impacts should then be compared to the expected reductions in total
2 electricity costs, so that the portfolio manager and regulators can evaluate the
3 trade-off that might have to be made between lower costs and higher rates.

4 Regarding the second issue, with due care in DSM program design, any residual
5 impacts among ratepayers can be mitigated. Among the ways to do so are the following
6 program design principles:

- 7
- 8 1. Efficiency programs should be designed to provide opportunities to all customer
9 classes and subclasses, and to address as many electric end-uses and technologies
10 as possible within cost-effectiveness guidelines.
 - 11 2. Efficiency programs should be designed to minimize the costs incurred by the
12 program administrator while still acquiring all cost-effective DSM resources.
 - 13 3. Efficiency programs should be designed to maximize the long-term avoided costs
14 savings for the electricity system, and up-to-date avoided costs should always be
15 used.
 - 16 4. Efficiency programs that result in lower rates should be combined with those that
17 might increase rates, to lower the overall rate impact.
 - 18 5. If there are concerns about interclass cross-subsidies, budgets for efficiency
19 programs targeted to a specific customer class (i.e., limited-income, residential,
20 commercial, industrial) could be allocated in some fair manner while recognizing
21 that DSM resources exist to be acquired from all customer classes and subclasses.
 - 22 6. As efficiency programs are expanded, there will be more participants and fewer
23 non-participants, thereby mitigating any residual problem.
- 24

25 The U.S. EPA sums up the situation nicely:

26 ***Some Say:***

27 Customers will pay more if utilities offer energy efficiency.

28 **The Fact Is:**

- 29
- 30 • Total bills can decrease 2% to 9% over a 10-year period.
 - 31 • Customer will pay more if new, more costly infrastructure is built to serve avoidable demand.

- Lower demand from efficiency programs puts downward pressure on market prices.

See, U.S. EPA at <http://www.epa.gov/cleanenergy/energy-programs/napee/index.html>.

Q. Has the Virginia legislature provided any guidance that may be used by the Commission to decide this question?

A. Yes, it has. In the legislation charging the SCC to open this proceeding, the Legislature directed that “The Commission shall determine which test should be given greatest weight when preparing a cost-benefit analysis of a demand-side management program, taking into consideration the public interest and the potential impact on economic development in the Commonwealth.” 2009 Acts of Assembly, Chapter 752 (House Bill 2531) and 2009 Acts of Assembly Chapter 855 (Senate Bill 1348) in the Second Enactment Clause, §1.²⁵ Furthermore, the 2009 Acts of Assembly 824 (House Bill 2506), which added 56-585.1.A.5.c, provides that in any rate recovery proceeding on an EE program, the SCC shall consider environmental protection. Specifically, it states: “In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection in the Commonwealth.”

Q. Are your recommendations on this question consistent with that guidance?

A. Absolutely.

The public interest favors use of the TRC Test for the purpose of determining whether a given measure or program design is cost effective or for field screening, for DSM goal setting, in program evaluation, or for evaluating the cost-effectiveness of the overall portfolio of a utility’s DSM programs. This is true for several reasons. The TRC Test is the only one of the industry-standard tests that results in least-cost service to ratepayers, a fundamental public interest duty of utilities and regulators alike.²⁶ It gives EE measures their due in resource selection, which advances the additional public interest purposes of risk reduction and environmental protection. In addition, the public interest in

²⁵ Hereinafter, I refer to this legislation as the SCC Energy Efficiency Potential Proceeding bill.

²⁶ To be clear, as explained above, the RIM Test and Participant Test fail to deliver on that obligation. There are also the Societal Test and the Utility System Test, but the Societal Test is a version of the TRC Test and the Utility System Test omits participant costs and, so, does not result in the lowest cost to society.

1 sound economic development is also favored by that choice for several reasons, including
2 the fact that DSM that is cost-effective in the sense of the TRC Test promotes a more
3 efficient economy in the Commonwealth, the ability to attract and keep green jobs—the
4 cutting edge of the future economy—the benefits to businesses large and small through
5 reduced price volatility, the delivery of lower, more predictable bills, and leads to the
6 creation of a substantial net number of new jobs directly in the delivery of programs and
7 indirectly through the greater economic multipliers for EE (and renewable energy) than
8 for traditional generation.²⁷ To the extent that the Commonwealth's economic vitality
9 depends on agriculture, tourism and ability to attract businesses and population to a
10 healthy and clean environment, the TRC Test adjustments I recommend below will
11 further enhance the test's ability to identify the best level of DSM activity.

12 Both the public interest and economic development favor the conclusion that the
13 RIM Test has no place in cost-benefit screening, either in program design or in field
14 screening, nor in goal setting or evaluation. Above, in this testimony, I have set out many
15 reasons for that conclusion, not the least of which is that use of RIM Test would lead to a
16 gross loss of efficiency for the entire Commonwealth economy.

17 **Q. Is it necessary to make a distinction between demand response programs and energy**
18 **efficiency programs? If so, why?**

19 A. As I demonstrate below, energy efficiency programs can have very different
20 effects on both customer bills and the utility cost of service than demand response
21 programs. Since customer bills affect the outcome of the Participant Test, and since the
22 utility cost of service affects the outcome of the TRC Test and the RIM Test, the
23 distinction between these types of programs should be kept in mind when considering
24 cost-effectiveness testing. In other words, the distinction between these two categories of
25 DSM measures is often important because energy efficiency produces very different
26 results than demand response and has very different implications for a utility's future
27 generation mix, environmental impacts, and revenue requirements.

28 More particularly, the significance of the distinction primarily stems from the fact
29 that reductions in total electricity consumption through energy efficiency result in greater

²⁷ I discuss this issue in more detail as part of my response to Commission question No. 5, below in this testimony.

1 reductions in annual supply costs and environmental impacts than reductions in peak
2 demand through demand response. In order to appreciate these differences, it is important
3 to understand the difference between electric capacity and electric energy. I illustrate the
4 difference between these two categories of supply and the different effects of demand
5 response and energy efficiency in three charts presented on pages 1 to 3 of Steinhurst
6 Exhibit 1, labeled "Exhibit SELC-WS-1."

7 The first chart, on page 1 of Steinhurst Exhibit 1, presents the aggregate electric
8 energy use of customers of a representative utility, by hour, over a year. The shaded area
9 represents aggregate electricity use in each hour plotted from the hour of highest
10 aggregate use to the hour with the lowest aggregate use. The hour of highest aggregate
11 use is typically referred to as peak demand.

- 12 • **Capacity.** In order to ensure reliable service, the utility serving this load will own
13 or control enough generating capacity²⁸ to serve the peak demand plus a reserve
14 margin, typically in the range of 15%. The utility incurs a fixed cost for this
15 capacity, regardless of whether it ever dispatches it to produce electric energy.
16 Therefore, the "marginal" source of such capacity is often a gas-fired combustion
17 turbine ("CT") plant, which has a low capital cost and a high operating cost.
- 18 • **Energy.** In order to supply the quantity of electricity that customers use in each
19 hour the utility generates and/or purchases electric energy.²⁹ However, it incurs a
20 variable cost for every MWh of electric energy generated. The cost of this energy
21 represents the largest portion of the cost of electricity supply to most customers,
22 which is much greater than the capacity cost. In addition, the acquisition and
23 combustion of fuels used to generate this energy produce the vast majority of the
24 environmental impacts associated with annual electricity use.³⁰

²⁸ Capacity is typically measured in megawatts ("MW") at the supply level and kilowatts ("kW") at the customer level.

²⁹ Energy is typically measured in megawatt-hours ("MWh") at the supply level and kilowatt-hours ("kWh") at the customer level.

³⁰ For example, most of the air and water pollution and greenhouse gas emissions resulting from a fossil fueled power plant over its lifetime are due to the extraction, refinement, transportation and combustion of fuel; only a modest amount are due to the energy used to construct and decommission the plant itself.

1 The second chart, on page 2 of Steinhurst Exhibit 1, illustrates the impact of a 5%
2 reduction in peak demand due to demand response. In this example, demand response
3 measures reduce customer energy use by 5% in relatively few hours of the year (*e.g.*, 90
4 out of 8760 hours). In response to this reduction the utility could reduce the quantity of
5 capacity it holds by 5%, and avoid the associated costs of that capacity. However, that
6 5% peak demand reduction would not produce a corresponding reduction in a customer's
7 annual bill. Moreover that reduction would result in little or no avoided air emissions
8 because it is not reducing annual electricity generation in a material way.

9 The third chart, on page 3 of Steinhurst Exhibit 1, illustrates the impact of a 5%
10 reduction in annual energy use. In this example, energy efficiency measures reduce
11 customer energy use by 5% in every hour of the year (8,760 hours). In response to this
12 reduction in energy use the utility could reduce the quantity of capacity it holds by 5%, as
13 well as reduce the quantity of electricity it generates in every hour by 5%. This 5%
14 annual electricity generation reduction would produce a corresponding decrease in a
15 participating customer's annual bill. It should also provide a corresponding reduction in
16 air emissions, including avoided carbon dioxide associated with the avoided electric
17 energy generation.

18 **Q. Can you illustrate the relative impacts of reductions in peak demand and in annual**
19 **energy on the annual bill of a representative small usage customer?**

20 **A.** Yes. I illustrate the impact of 5% reductions in peak demand and annual energy
21 on a low-usage customer, such as a small commercial customer of Delmarva Power in
22 Virginia. For this illustration I consider two such customers based upon usage and typical
23 bill data drawn from the *Typical Bills and Average Rates Report* published by the Edison
24 Electric Institute.

25 The two customers in this example each have a peak demand of 3 kW. Customer
26 A has annual usage of 4,500 kWh, an annual bill of \$564 and a relatively low load factor
27 of 17%.³¹ Customer B has an annual usage of 12,000 kWh, an annual bill of \$1,368 and a

³¹ Load factor is a ratio that measures relative use of capacity. It is equal to annual energy use (kWh) divided by peak demand in kW multiplied by 8,760 hours.

1 mid-range load factor of 46%. I use illustrative values of \$80/kW-yr for avoided capacity
2 and \$0.08/kWh for avoided energy costs.

3 The inputs and results of this example are presented in Steinhurst Exhibit 2,
4 labeled "Exhibit SELC-WB-2." First, I calculate the impact on annual bills of a 5%
5 reduction in peak demand in 1% of the hours of a year. The savings were approximately
6 2.3% and 1.0% for customers A and B respectively. Next, I calculate the impact on
7 annual bills of a 5% reduction in energy use in every hour of the year, i.e. a 5 % reduction
8 in annual energy use. The impacts on annual bills were much larger, with savings of
9 approximately 5.3% and 4.4% for customers A and B respectively.

10 These illustrative results indicate that a given percentage reduction in peak
11 demand does not provide a corresponding reduction in the annual bill of a representative
12 small customer, while the same percentage reduction in annual energy consumption does
13 produce a corresponding decrease in a participating customer's annual bill.

14 **Q. At times, the Commission might be faced with balancing DSM strategies that**
15 **prioritize electric energy savings and DSM strategies that prioritize peak reduction.**
16 **Do your recommendations regarding cost-benefit tests assist the Commission with**
17 **such a balancing?**

18 A. Yes, they do.

19 **Q. Please explain.**

20 A. The cost-benefit test recommendations I have made in this testimony concentrate
21 on the effect DSM measures and programs will have on the costs faced by the utility and
22 its customers, together. This automatically gives energy efficiency and demand response
23 measures each their due in comparisons. The combination of measures and programs of
24 both kinds that delivers the least-cost life-cycle resource mix will be identified if the
25 analysis is properly conducted.

26 **Q. Is there any other reason the Commission should ensure it has given full**
27 **consideration to energy efficiency and not overly relied on demand response**
28 **programs?**

29 A. Yes. In the 2007 Acts of Assembly Chapter 888 (House Bill 3068) and the
30 identical senate bill, 2007 Acts of Assembly Chapter 933 (Senate Bill 1416), Enactment
31 Clause 3 (commonly referred to as the 2007 "Re-Regulation" bill) Section 3 of H 3068,
32 enacted on April 4, 2007, states, in relevant part:

1 3. That it is in the public interest, and is consistent with the energy policy goals in
2 § 67-102 of the Code of Virginia, *to promote cost-effective conservation of energy*
3 *through fair and effective demand side management, conservation, energy*
4 *efficiency, and load management programs, including consumer education. . . .*
5 *The Commonwealth shall have a stated goal of reducing the consumption of*
6 *electric energy by retail customers through the implementation of such programs*
7 *by the year 2022 by an amount equal to ten percent of the amount of electric*
8 *energy consumed by retail customers in 2006. The State Corporation Commission*
9 *shall conduct a proceeding to . . . (ii) identify the mix of programs that should be*
10 *implemented in the Commonwealth to cost-effectively achieve the defined electric*
11 *energy consumption reduction goal by 2022, including but not limited to demand*
12 *side management, conservation, energy efficiency, load management, real-time*
13 *pricing, and consumer education The Commission shall, on or before*
14 *December 15, 2007, submit its findings and recommendations to the Governor*
15 *and General Assembly, which shall include recommendations for any additional*
16 *legislation necessary to implement the plan to meet the energy consumption*
17 *reduction goal. [emphasis added]*

18 I am not an attorney, but it is my opinion that competent experts in electric utility
19 resource planning would, in practice, implement this language by ensuring that, in any
20 situation requiring a choice or comparison between energy efficiency measures and
21 demand response measures, the full benefits of energy efficiency (per the Adjusted TRC)
22 were reflected and that demand response measures, programs or goals were accorded a
23 priority no greater than justified under the Adjusted TRC. In addition, I note that the
24 Legislature has expressed a policy priority for environmental protection (cited above in
25 this testimony), singled out energy efficiency (as opposed to peak reduction) for goal
26 setting and certain utility incentives, while declining to maintain statutory language
27 authorizing utility incentives for peak-shaving programs. 2009 Acts of Assembly 824
28 (House Bill 2506), Enacting Clause 1, amending Va. Code § 56-585.1.5.b. Therefore, I
29 conclude that such practitioners would also exert extra effort to ensure that all cost-
30 effective energy efficiency resources were identified and implemented, that no
31 opportunities for energy efficiency were lost due to lack of new construction or
32 remodeling programs, and prioritize energy efficiency programs for management

1 attention, early process evaluation, marketing priority, access to capital, and other
2 discretionary actions.³²

3
4 **Commission Question No. 3. How should the Commission define the terms "achievable,"**
5 **"cost-effective," and "be realistically accomplished" as they are used in the statute cited**
6 **above?**

7
8 **Q. What is the source of this Commission Question?**

9 A. The terms are those used in the identical Acts of Assembly Chapter 855 (Senate
10 Bill 1348) and Chapter 752 (House Bill 2531) of the 2009 Acts of Assembly- the SCC
11 Energy Efficiency Potential Proceeding bill, which states, in relevant part:

12 2. § 1. That the State Corporation Commission shall conduct a formal public
13 proceeding that will include an evidentiary hearing for the purpose of determining
14 achievable, cost-effective energy conservation and demand response targets that
15 can realistically be accomplished in the Commonwealth through demand-side
16 management portfolios administered by each generating electric utility in the
17 Commonwealth.

18 **Q. Before responding to the Commission's request for recommended definitions, please**
19 **explain how expert practitioners in the field of utility resource planning would**
20 **understand the relationship of those terms.**

21 A. Expert practitioners in the field of utility resource planning would usually
22 consider a different set of three terms in thinking about goal setting for utility DSM.
23 Those terms are "technical potential," "cost-effective potential," and "achievable
24 potential." One can think of these three terms as forming the rings of a target, one inside
25 another, with technical potential being the largest ring and achievable potential the
26 smallest.

27 Briefly, the key terms may be defined as follows: (1) technical potential refers to
28 savings that could be obtained from a purely engineering point of view; (2) cost-effective
29 potential (often called "economic potential") means that sub-set of the technical potential
30 that are cost-effective; and (3) the achievable potential is the largest sub-set of the cost-

³² My concern about losing energy efficiency opportunities (usually referred to as "lost opportunity" resources) and specific recommendation about that issue are given later in this testimony.

1 effective potential that can be acquired in a particular period of time with an appropriate
2 set of policies and resources. Comparable definitions are provided in the *National Action*
3 *Plan for Energy Efficiency*, to which many experts would turn for guidance, and the
4 *National Action Plan* definitions are in general agreement with those I have been using
5 since the early 1980s, except for one tricky point that I discuss later in this testimony.

6 The *National Action Plan* provides the following definitions for these terms, plus
7 two other related terms:³³

- 8 • **Technical potential** assumes the complete penetration of all energy efficiency
9 measures that are considered technically feasible from an engineering perspective.
- 10 • **Economic potential** refers to the technical potential of those measures that are
11 cost-effective, when compared to supply-side alternatives. The economic potential
12 is very large because it sums up the potential in existing equipment, without
13 accounting for the time period during which the potential would be realized.
- 14 • **Maximum achievable potential** describes the economic potential that could be
15 achieved over a given time period under the most aggressive program scenario.
- 16 • **Achievable potential** refers to energy saved as a result of specific program
17 funding levels and incentives. These savings are above and beyond those that
18 would occur naturally in the absence of any market intervention.
- 19 • **Naturally occurring potential** refers to energy saved as a result of normal
20 market forces, that is, in the absence of any utility or governmental intervention.³⁴

21 The *National Action Plan* defines technical potential, economic potential, and
22 naturally occurring potential in a manner consistent with the way I would. I also agree
23 with its definition of maximum achievable potential, as far as it goes. (I would clarify that
24 “the most aggressive program scenario” should mean one that is not constrained by

³³ I would note that Dominion’s witness also discuss these terms, but define them in a different way. I believe that my discussion is more consistent with the best practice and thinking in the field of DSM potential estimation, program design and goal setting.

³⁴ July, 2006, p. 6-17. Available at http://www.epa.gov/cleanenergy/documents/napee/napee_report.pdf. An Executive Summary is available at http://www.epa.gov/cleanenergy/documents/napee/napee_exsum.pdf. As explained on <http://www.epa.gov/cleanenergy/energy-programs/napee/index.html>, “The National Action Plan for Energy Efficiency is an ongoing effort led by a Leadership Group of more than 60 leading gas and electric utilities, state agencies, energy consumers, energy service providers, and environmental/energy efficiency organizations.”

1 arbitrary or extraneous budget limits, utility preferences, or any similar factors.) As I
2 explain shortly, there is one tricky step in the process of applying the *National Action*
3 *Plan's* terminology to the relevant Virginia statutory terms from the SCC Energy
4 Efficiency Potential Proceeding bill, and I will explain how to make that conversion.

5 **Q. Can you correlate those definitions to the terms mentioned by the Commission?**

6 A. In part. As shown in below in Figure 2, the Virginia statute's term "cost-
7 effective" would be understood by expert practitioners as directly equivalent to the
8 Action Plan's definition of economic potential, a subset of the technical potential. That is
9 straightforward.

10 Correlating the statute's "achievable potential" with the *National Action Plan's*
11 terms requires a bit more thought. The statute's reference to potential "that can
12 realistically be accomplished" suggests a level of EE potential below the EE potential
13 that is "achievable." Thus, in the context of the statute, "achievable" potential lies
14 between "cost-effective potential and "realistically accomplishable" potential. Similarly,
15 under the *National Action Plan*, the "maximum achievable" potential occupies the middle
16 ground- falling between "economic" potential (which is higher than "maximum
17 achievable") and "achievable" potential (lower than the "maximum achievable"). So, it
18 would be reasonable to equate the statute's "achievable potential" with the *National*
19 *Action Plan's* term "maximum achievable" potential. I recommend that the Commission
20 equate these terms accordingly.

21
22
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Figure 2

Comparison of *National Action Plan for Energy Efficiency*
and Virginia Statutory Terms for Energy Efficiency
Potential

<i>National Action Plan for Energy Efficiency</i>		Virginia Statute
Technical Potential	↔	N/A
Economic Potential	↔	Cost-effective Potential
Maximum Achievable Potential	↔	Achievable Potential
Achievable Potential	↔	Realistically Accomplishable Potential

1

2 **Q. That leaves us with the job of defining the amount that "can be realistically**
 3 **accomplished." How do you answer that part of the Commission's Question?**

4 A. It might seem simple at this point to equate "can be realistically accomplished"
 5 with the *National Action Plan's* term "achievable," but there is a problem with the
 6 definition in the *National Action Plan*, at least for the purpose of this proceeding.
 7 Possibly due to its national policy focus, the *National Action Plan's* explanation of
 8 "achievable" potential is incomplete in that it does not specify how "specific program
 9 funding levels and incentives" are to be determined (other than the fact that those levels
 10 and incentives may be something short of the "most aggressive program scenario"
 11 associated with the "maximum achievable" potential). Thus, under the *National Action*
 12 *Plan* there is a vague gap between "maximum achievable" and the merely "achievable."
 13 This is a crucial gap because only by bridging it (i.e., more precisely explaining the
 14 difference between "maximum achievable" and "achievable") can the *National Action*
 15 *Plan's* "achievable potential", and by extension the statute's "realistically
 16 accomplishable" potential, be given the level of detail that can give the Commission a
 17 practical understanding of the meaning "realistically accomplishable" energy efficiency.

18 **Q. How should the Commission address that gap?**

19 A. The problem here is what level of "program funding levels and incentives" can
 20 tell us the amount of DSM that "can realistically be accomplished." I recommend that
 21 Commission resolve this matter by following the general practices and guidelines for
 22 integrated resource planning ("IRP") in determining how much potential is "realistically

1 accomplishable” (that is, how much of the “maximum achievable” potential is
2 “achievable” in the terms of the of the *National Action Plan*).

3 I wish to be quite clear that, here, I am talking about a best-practices model of
4 IRP. I am not basing this discussion on the specific Virginia statute. In a properly defined
5 IRP process, there are two key principles that drive all other considerations. They are (1)
6 a level playing field for demand- and supply-side resources (as well as renewable
7 resources vs. other generation) and (2) least cost planning.³⁵ That is the kind of IRP that
8 serves the public interest because it leads to the overall least cost service that will meet
9 consumers’ needs. It drives utilities to focus on their most fundamental obligations. It is
10 IRP-compliant DSM programs that are compliant with such an IRP process that will
11 protect the utility and its customers “from mandated expenditures with uncertain future
12 benefits.”³⁶ Thomas prefiled at 7, l. 8. To the extent that a utility may express concerns
13 about premature commitment to strong DSM goals or a need to await exploration of IRP
14 concepts in a future proceeding, twenty years of experience with IRP processes around
15 the country give the Commission ample basis for proceeding with DSM goals and
16 mandates.

17 **Q. Why are IRP practices and guidelines relevant and appropriate to the**
18 **Commission’s decisions under the cited statute?**

19 **A.** The most fundamental obligation of a public utility is to provide adequate service
20 at least cost. Failure of a utility to do so implies that its rates are not just and reasonable
21 because its costs, being more than least cost, must include costs that are unnecessary, not
22 used and useful, or are imprudent. *See*, for example, Va. Code § 56-234.3 (“Approval of
23 expenditures for and monitoring of new generation facilities . . .”). For some twenty
24 years, it has been widely recognized by Commissions around the country that for
25 regulated energy utilities IRP is a suitable means for comprehensive and effective pursuit
26 of that goal.

27 **Q. Do IRP practices and guidelines call for such decisions to be made in specific ways?**

³⁵ These key principles are discussed in NRRI’s *Electricity at a Glance*, available at http://nrri.org/pubs/electricity/electricity_at_a_glance.pdf.

³⁶ Thomas testimony at 7.

1 A. Yes. In particular, as I mention above, there are two broad principles that are
2 central to IRP practice. The first is that all resources are to be considered on a “level
3 playing field.” That is, the development of the IRP considers all resources that may
4 contribute to meeting need. It also means that energy efficiency and demand response
5 (together, demand-side management) resources, transmission and distribution resources
6 (including improvements to transmission and distribution efficiency), and all types of
7 generation resources must be considered on an equal basis. The second broad principle is
8 that the planning process should result in an integrated portfolio of resources with the mix
9 of resources that will provide adequate and reliable service at the lowest life cycle cost.
10 Life cycle cost comparisons (between resources or portfolios) should be made using
11 either the TRC Test or the Societal Test. Each of these tests has its own advantages, but
12 generally speaking the TRC Test is somewhat easier to implement, while the Societal
13 Test is more comprehensive in the costs and benefits that it considers.

14 As both of these IRP principles are calculated to lead to adequate and reliable
15 utility service at least cost to consumers, it would be sound public policy for the
16 Commission to use them in the IRP context to determine that the “target that can
17 realistically be accomplished” should differ from the *National Action Plan’s* “maximum
18 achievable potential” *only* to the extent that specific evidence demonstrates that a specific
19 portion of the maximum achievable potential *cannot* be acquired due to a physical, legal
20 or other practical and irremediable barrier.

21 **Q. Is it your testimony that Virginia utilities must or should prepare IRPs?**

22 A. I understand that this is now a requirement in Virginia under Va. Code §§ 56-597
23 through 599, with the first IRPs due by September, 2009. But my point is that the
24 principles that underlay IRP in many jurisdictions are also an appropriate policy
25 foundation for making the translation from “maximum achievable potential,” as the
26 *National Action Plan* puts it, to “realistically accomplishable potential” as used in
27 Virginia statute (i.e., what policies and resource allocations should be used to determine
28 the proper achievable potential for the Commonwealth's electric utilities). In my opinion,
29 it would be appropriate and wise for the Commission to recognize the more than twenty-

1 five years of IRP experience nationally in the field of power planning and, as a matter of
2 policy, rely on those principles to resolve this issue.

3 **Q. So, again, how do the Virginia statute's terms "achievable" and "can realistically be**
4 **accomplished" relate to the *National Action Plan's* terms?**

5 A. The statute directs the Commission to inquire separately about "achievable"
6 potential and the potential "that can realistically be accomplished." This suggests that
7 there could be a difference between the two. One end point of a typical DSM potential
8 study is typically an estimate of what the *National Action Plan* calls "achievable"
9 potential, a similar position occupied in the context of the Virginia statute by
10 "realistically accomplishable" potential. Therefore, I believe that the Virginia statute's
11 "targets that can realistically be accomplished," just like the Action Plan's "achievable"
12 potential, should differ from the Action Plan's "maximum achievable potential" *only* to
13 the extent that specific evidence demonstrates that a specific portion of the maximum
14 achievable potential *cannot* be acquired due to a physical, legal or other practical and
15 irremediable barrier.

16 **Q. With that clarification, what definitions do you recommend to the Commission for**
17 **the statute's terms?**

18 A. I recommend that the Commission adopt the following definitions for use in the
19 context of the cited statute:

- 20 1. Cost-effective DSM potential means the technical potential of those measures that are
21 cost-effective, when compared to supply-side alternatives.
- 22 2. Achievable DSM potential means the economic (i.e., cost-effective) potential that
23 could be achieved over a given time period under the most aggressive program
24 scenario.
- 25 3. Targets that can realistically be accomplished also means the achievable DSM
26 potential except to the extent that specific evidence demonstrates that a specific
27 portion of the maximum achievable potential *cannot* be acquired due to a physical,
28 legal or other practical and irremediable barrier to acquiring some particular cost-
29 effective resource in some particular market segment other than budget limitations.
30 Such targets may reflect adjustments for a brief ramp up period, not to exceed three
31 years.

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Commission Question No. 4. How should the Commission determine the "public interest" in preparing a "cost benefit analysis of a demand-side management program"?

Q. What public interest factors should the Commission consider for establishing utility DSM targets and analyzing the cost and benefits of a DSM program?

A. When deciding what is in the public interest, the Commission should consider the total life-cycle cost of service, external costs, risk reduction, equity in program availability, and protection of hard to reach customers. The bottom line is that all cost effective savings are in the public interest. Anything less means that ratepayers will see higher bills than necessary, shoulder huge unnecessary financial and other risks, and see a less vigorous overall economy in the Commonwealth. Therefore, the public interest demands that decisions about how to analyze the costs and benefits of DSM programs, as well as the setting of utility DSM targets, reflect the impact of each measure and program on the total life cycle cost of service of the utility's resource portfolio.³⁷ As explained above, the TRC Test is the proper way to do that. For the same reason, it is desirable to also consider external costs to society, risk reduction, equity in program availability, and consumer protection. I make certain recommendations to adjust the TRC Test and recommend certain additional DSM program policies to accomplish those requirements.³⁸

In addition, as discussed elsewhere, Virginia statute, Va. Code 56-585.1.A.5.c., requires consideration of "environmental protection" in approving EE programs, so it certainly makes sense for the Commission to factor that into its decision making on the public interest. There is no doubt that environmental protection is a valid public interest, and energy efficiency programs are, without a doubt, the most effective and cost-effective way to advance that interest.

Q. How else should the Commission take the public interest into account in analyzing the costs and benefits of a DSM program?

³⁷ As mentioned earlier in this testimony, the TRC Test compares the life cycle present value of a measures savings to the life cycle present value of its costs.

³⁸ It bears repeating in the context of this Commission question that using either the Participant Test or the RIM Test to influence cost-benefit analysis in any way defeats the public interest. As discussed above, those two tests have legitimate uses, but not in cost-benefit testing.

1 A. The Commission can best protect the public interest by following these three
2 steps. First, as recommended elsewhere in this testimony, I recommend that utilities rely
3 on the TRC Test (as adjusted according to this testimony) and *only* the TRC Test in cost-
4 benefit analysis, both for program design and for field implementation. Second, I
5 recommend that the full costs and risks of supply-side alternatives are reflected in that
6 analysis, especially the potentially huge cost of expensive new base load plants, fossil
7 fueled or otherwise. Third, I recommend that utility DSM targets equal the maximum
8 achievable potential (as used in the *National Action Plan*), reducing those estimates only
9 on evidence that there is a specific and objectively documented physical, legal or
10 practical barrier to acquiring some particular cost-effective resource in some particular
11 market segment other than a (desired or proposed) budget limitations. This is consistent
12 with my explanation of how the statutory term potential “that can realistically be
13 accomplished” should be defined by the Commission. (See my response to Commission
14 question No. 3, above.) SELC witness Loiter provides specific numerical goal
15 recommendations in his direct prefiled testimony.

16 As explained above, the Commission should keep in mind that energy efficiency
17 and efficiency measures (1) are generally more cost effective and advance the public
18 interest more than demand response measures and (2) ensure that energy efficiency and
19 efficiency options are not short changed at any step in the process—from framing
20 technical potential studies to the final program decisions and implementation—to the
21 benefit of demand response or supply-side options.

22 **Q. Regarding your second step, what is the source of your concern about the potential**
23 **cost of expensive new base load plants, fossil fueled or otherwise?**

24 A. DSM typically compares favorably to new generation. For example, a recent
25 study concluded that, “these policy and programs [a package of energy efficiency
26 policies, primarily utility DSM] can accomplish this [meeting Virginia’s needs] at a
27 lower cost than building new generation and transmission, while at the same time
28 creating nearly 10,000 new, high-quality “green collar” jobs by 2025.”³⁹

³⁹ ACEEE, et al., *Energizing Virginia: Efficiency First*, September, 2008. Available at <http://aceee.org>.

1 Not only is DSM a better buy for ratepayers than expensive new coal plants, but
2 costs for capital intensive base load plant have climbed rapidly in recent years. The
3 Brattle Group, in a report prepared for the EDISON Foundation of the Edison Electric
4 Institute concluded that:

5 Construction costs for electric utility investments have risen sharply over the past
6 several years, due to factors beyond the industry's control. Increased prices for
7 material and manufactured components, rising wages, and a tighter market for
8 construction project management services have contributed to an across-the-board
9 increase in the costs of investing in utility infrastructure. These higher costs show
10 no immediate signs of abating.⁴⁰

11 Indeed, those trends have not abated. For example, a report issued in June of this year
12 found that

13 . . . significant cost increases have been announced for almost all other proposed
14 coal-fired power plants in recent years. For example, the estimated per unit
15 construction cost of Duke Energy Carolina's Cliffside Project increased by 80
16 percent between the summer of 2006 and June 2007. Similarly, the projected
17 construction cost of Wisconsin Power & Light's now cancelled Nelson Dewey 3
18 coal plant increased by approximately 47 percent between February 2006 and
19 September 2008. The estimated cost of AMP-Ohio's proposed Meigs County
20 Coal Plant nearly tripled in the three years between October 2005 and October
21 2008.⁴¹

22 Nor are nuclear plants immune from this trend. The Toronto Star has reported that

23 Energy and Infrastructure Minister George Smitherman announced on June 29 he
24 was suspending a competitive process for the purchase of new reactors for
25 Ontario. He cited the price tag as "billions" too high, but would not reveal the
26 amount of the bid from AECL, deemed the only compliant proposal out of three
27 offers.

28 AECL's \$26 billion bid was based on the construction of two 1,200-megawatt
29 Advanced Candu Reactors, working out to \$10,800 per kilowatt of power
30 capacity.⁴²

31 Of course, the serious lack of managerial and strategic flexibility inherent in
32 making financial commitments to such large base load plants 8 to 10 years before any

⁴⁰ The Brattle Group, *Rising Utility Construction Costs: Sources and Impacts*, September 2007, at page 31.

⁴¹ David Schlissel and Lucy Johnston, *Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan*, June 2009, p. 15. Available at <http://www.synapse-energy.com/Downloads/SynapseReport.2009-06.0.East-Kentucky-Power-Cooperative-Assessment.09-012.pdf>.

⁴² Tyler Hamilton, "\$26B cost killed nuclear bid: Ontario ditched plan over high price tag that would wipe out 20-year budget," *Toronto Star*, July 14, 2009. Available at <http://www.thestar.com/Business/article/665644>.

1 benefits are possible makes the prospect of such cost increases even more of a concern
2 of ratepayers. Few if any industries without captive customers would tolerate the
3 possibility that \$10 billion investment could turn into a liability with little warning.

4 **Q. Overall, how does energy efficiency stack up against generation alternatives?**

5 A. It is "hands down" the cheapest way to provide for Virginia's energy needs right
6 now and for the foreseeable future. The most responsible way for the utilities to spend the
7 ratepayers' money is spend it on EE, not new plants. The discussion above regarding the
8 public interest and its relationship to least-cost planning supports this conclusion.

9 **Q. Are you familiar with a recent study that demonstrates this point?**

10 A. Yes. In December, 2007, McKinsey & Co. published a report on the costs of
11 various measures for reducing greenhouse gas emissions in the U.S.⁴³ Of particular
12 interest in this regard is Exhibit B on page xiii of that report. That exhibit shows the vast
13 amount of emission reduction available in the U.S. from energy efficiency programs at
14 cost that are not only less than any generation alternative, but *that are less than the cost*
15 *of doing nothing at all.* (That means those measures save more than they cost.)
16

17 **Commission Question No. 5. What is the potential impact of the generating electric utility's**
18 **demand-side management program on economic development in the Commonwealth?**
19

20 **Q. Has the question of the potential impact of utility DSM programs on economic**
21 **development been analyzed?**

22 A. Yes, there have been a number of studies of this question. Typically, the
23 conclusion is that the economic stimulus provided by utility (and non-utility) DSM
24 programs is substantial. For example, one finding of the *Staff's Report to the State*
25 *Corporation Commission in preparation for the Commission's Report to the Governor*
26 *and the General Assembly* was that

27 [m]ost sub-groups believed mass implementation of energy efficiency and
28 conservation efforts would generate benefits to ratepayers and the state economy
29 by helping to offset future increases in energy costs, provide electric system

⁴³ Jon Creyts, et al., *Reducing Greenhouse Gas Emissions: How Much at What Cost?* Available at
http://www.mckinsey.com/client-service/ccsi/pdf/US_ghg_final_report.pdf

1 reliability benefits, offer customers the ability to better manage their energy costs,
2 and maintain a competitive regional economy. Additionally, effective programs
3 could help accelerate Virginia's environmental and air quality goals while helping
4 to reduce the costs associated with future climate change policies.⁴⁴

5 From a more quantitative point of view, the ACEEE and a team of other
6 consulting groups (including certain staff at Synapse, but not myself) estimated an Policy
7 Case (Medium Scenario) cumulative peak load savings of 26% in 2025—19% from
8 energy efficiency and 7% from demand response. On the energy side, the Policy Case
9 (Medium Scenario) cumulative savings was 19% in 2025, of which about 15% was from
10 utility DSM programs.⁴⁵ The resulting annual net consumer savings estimated from
11 reduced electricity consumption and from lower prices, net of participant costs was about
12 \$480 million per year in 2015, and about \$2.2 billion per year in 2025. The net
13 cumulative savings to consumers was \$1 billion in 2015 and about \$15 billion by 2025.

14 The 2008 ACEEE study also presented the results of a detailed macroeconomic
15 modeling of how those savings (and the costs of delivering them) affected Virginia's
16 economy. The estimated net contribution to Virginia employment (full-time job
17 equivalent) was 675 in 2015 and 9820 in 2025. This is largely driven by the fact that the
18 electric services sector in Virginia is much less labor intensive than the energy efficiency
19 sector. The net contribution given here reflects both sides of that equation. In addition
20 "the increase in jobs and the changes in job mix result in a net gain to the state's wage and
21 salary compensation" (in 2006 dollars) of \$63 million per year in 2015 and \$583 million
22 per year in 2025. The net gain to the Virginia's Gross State's Product (also in 2006
23 dollars) was estimated to be \$202 million per year in 2015 and \$882 million per year in
24 2025.⁴⁶

25 As a further example, I conducted a study that modeled, among other matters, the
26 economic impacts of the DSM and renewable generation policies of the New England

⁴⁴ SCC Staff, *Staff's Report to the State Corporation Commission in preparation for the Commission's Report to the Governor and the General Assembly*, November 2007, pp. 4 and 27.

⁴⁵ ACEEE, et al., *Energizing Virginia: Efficiency First*, September, 2008, Table 10, p. 24. Available at <http://aceee.org>. Specifically, Synapse assisted ACEEE in the development of the avoided cost projections used in that report. I was not part of the Synapse team on that project and have no personal knowledge of the work done beyond what is in the published report.

⁴⁶ *Ibid.*, p. 40-41.

1 states as they played out during calendar years 2000 through 2004. The study showed that
2 an investment of about \$1.2 billion in energy efficiency programs resulted in a reduction
3 in annual electricity requirements of over 3.5 million MWh. The average cost was on the
4 order of 2.4 cents/kWh despite ten previous years of intensive DSM programs. As to the
5 regional economy, that investment resulted in a net increase in the region's economic
6 output of about \$2 Billion (2001\$), a net increase in income to workers of \$694 million
7 (2001\$), and a net increase in employment of nearly 15,000 job-years.⁴⁷ Similar results
8 have been found in numerous other studies around the country.⁴⁸

9 **Q. What do you conclude regarding the potential impact of the generating electric**
10 **utility's demand-side management program on economic development in the**
11 **Commonwealth?**

12 A. It is clear from both the general literature and Virginia-specific studies that
13 aggressive, well-funded utility DSM programs based on least cost planning principles and
14 the TRC Test strongly promote a vital state economy—much more so than equivalent
15 investment in generation or T&D. A report by the Massachusetts Office of Consumer
16 Affairs and Business Regulation summed up the general experience in this way:

17 The Division estimates that 2002 Program expenditures (plus associated
18 participant costs) added 1,778 new jobs to the Massachusetts economy in 2002.
19 The majority of jobs were created in the services industry (44 percent), followed
20 by manufacturing (17 percent) retail trade (14 percent), construction (9 percent),
21 and wholesale trade (7 percent). These new jobs added \$139 million to the gross
22 state product, including \$64 million in disposable income in 2002 alone. The
23 1,778 jobs created in 2002 are short-term jobs, lasting the length of time needed
24 for installation and production of the energy efficiency measures. These positive
25 economic impacts of energy efficiency programs are consistent with results from

⁴⁷ Richard Sedano, et al., *Electric Energy Efficiency And Renewable Energy In New England: An Assessment of Existing Policies and Prospects for the Future*, The Regulatory Assistance Project, May 2005. The economic impact information is in App. C to that report—William Steinhurst, et al., *Modeling Economic and Environmental Effects of Investments in Energy Efficiency and Renewable Energy*, Synapse Energy Economics. Available at <http://www.synapse-energy.com/Downloads/SynapseReport.2005-05.RAP-EPA.Efficiency-and-Renewable-Energy-in-New-England.04-23.pdf>.

⁴⁸ For example, Marshall Goldberg, Martin Kushler, Steven Nadel, Skip Laitner, Neal Elliott, and Martin Thomas, *Energy Efficiency and Economic Development in Illinois*, ACEEE, December, 1998; U.S. DOE, *The Jobs Connection: Energy Use and Local Economic Development*, Nov. 1996.

1 studies performed in other states, including analyses in Iowa and Illinois, as well
2 as a combined study in New York, New Jersey and Pennsylvania.⁴⁹

3
4 Setting aggressive DSM targets and vigorously overseeing their prompt pursuit is
5 the best thing the Commission can do for the Commonwealth's economy at this time.

6 **Q. Do the utility witnesses agree with you on this point?**

7 A. Not entirely. For example, APCO witness Castle admits "overall expenditures on
8 electricity will be lower in the longer term than they otherwise would have been through
9 the use of traditional supply options." However, he also claims that while jobs will be
10 created through DSM program spending, the costs of those programs to consumers will
11 reduce spending.⁵⁰ This overlooks the relative magnitude of those (and other related)
12 influences. The studies I reviewed above (and all properly conducted studies of such
13 effects) net out the suppressive effects that concern him and report the net benefits.
14 Dominion witness Venable does not appear to express a firm opinion either way.⁵¹

15
16 **Commission Question No. 8. How should the Commission "determine a just and**
17 **reasonable ratemaking methodology to be employed to quantify the cost responsibility of**
18 **each customer class to pay for generating electric utility-administered demand-side**
19 **management programs"?**
20

⁴⁹ 2002 *Energy Efficiency Activities: A Report by the Division of Energy Resources*. Available at http://www.mass.gov/Eoeea/docs/doer/electric_deregulation/ee02-long.pdf. The studies cited in that report were: Weisbrod, Glen, Hagler Bailly Consulting Inc, et al, *Final Report: The Economic Impact of Energy Efficiency Programs and Renewable Power for Iowa*, Prepared for the Iowa Department of Natural Resources, December 1995; Goldberg, Marshall et al, *Energy Efficiency and Economic Development in Illinois*, American Council for an Energy-Efficient Economy (ACEEE), December 1998; and Nadel, Steven et al, *Energy Efficiency and Economic Development in New York, New Jersey and Pennsylvania*, ACEEE, February 1997. More recent studies with comparable results include Ian Goodman, *National Grid's Energy Efficiency Programs: Benefits for Rhode Island's Economic Development and Environment*, prepared for National Grid USA, July 2006 (available at http://www.thegoodman.com/pdf/081010033713_TGG20060728_NGridRI_Jobs.pdf); Lisa Petraglia, Glen Weisbrod and Brian Baird, *Economic Development Benefits: FY07 Economic Impacts Report*, February 2007, prepared for the Wisconsin Department of Administration (available at http://www.focusonenergy.com/data/common/dmsFiles/E_EC_RPTI_Econ_Dev_Benefits_FY07.pdf); and Howard Geller and Marshall Goldberg, *Energy Efficiency and Job Creation in Colorado*, April 2009 (available at http://www.swenergy.org/pubs/EE_and_Jobs_Creation_in_Colorado-April_2009.pdf).

⁵⁰ Castle testimony at 11.

⁵¹ Venable testimony at 18-19.

1 **Q. What is your recommendation for a just and reasonable ratemaking methodology to**
2 **be employed to quantify the cost responsibility of each customer class to pay for**
3 **generating electric utility-administered demand-side management programs?**

4 A. I recommend the Commission allocate utility DSM program costs among all rate
5 classes. The specific class allocators could be determined in various ways. I have not
6 reviewed the Commission's specific rate design practices, but can give the reasons for my
7 recommendation and offer a general explanation of my view of class cost allocators for
8 DSM.

9 **Q. Please do so.**

10 A. DSM is a resource that provides system-wide benefits in addition to any benefits
11 it provides to program participants or, even, to the specific rate classes to which the
12 program participants belong. For any DSM measure or program, the fact that it passes the
13 TRC Test is an affirmation of system wide benefit on its own. In addition, DSM
14 measures and programs that are cost-effective under the TRC Test also deliver broad,
15 system-wide benefits through reduced external costs, by reducing market clearing prices
16 for electricity, ancillary services and natural gas, and, perhaps most importantly (by
17 moving the clearing price "down the supply curve"), the capital costs and financial risks
18 entailed in any avoidable future capacity costs for generation or T&D facilities (aside
19 from customer-specific facilities).

20 In other words, while DSM program participants who reduce the quantity of
21 electric energy they consume see a benefit on their bills, to the extent that DSM measures
22 reduce the need for new capacity, the costs of which are recovered from everyone, there
23 is a system wide benefit. For that reason, alone, it is appropriate to allocate DSM program
24 costs among all rate classes. The Commission should also take note of the fact that the
25 financial, regulatory and operational risks avoided by a reduced need for new capacity, as
26 well as a reduced reliance on volatile fuel prices, accrue to all ratepayers through less
27 volatility and uncertainty in retail rates and, even more broadly, lower the cost of capital
28 that can accrue to utilities that avoid those risks. These risk benefits are above and
29 beyond those generally accounted for in the TRC Test but would be recognized, at least

1 in part, by the 10% risk adjustment I recommend be required in the application of the
2 TRC Test.

3 As explained by APCO witness Thomas, the choice of an allocation factor will
4 depend upon the type of the system-wide benefits, in a manner equivalent to the
5 allocation of supply resource costs on the basis of "cost causation."⁵² However, I
6 disagree with his suggestion that *all* the costs of energy efficiency programs be allocated
7 using energy factors. The choices of allocation factors according to classification of
8 system-wide benefits should include the following:

- 9 1. Costs for programs that produce energy-related benefits should be allocated using an
10 "energy" allocation factor (e.g. annual kWh by rate class)
- 11 2. Costs for programs that produce capacity-related benefits should be allocated using a
12 "capacity" allocation factor (e.g. kW of coincident peak by rate class)
- 13 3. Costs for programs that produce a combination of energy and capacity benefits
14 consistent with average annual supply costs should be allocated using an annual
15 supply cost allocation factor (e.g. annual supply costs by rate class).

16 **Q. You have referred to the risk-avoidance benefits of utility DSM programs. Can you**
17 **explain those benefits?**

18 A. I have done so earlier in this testimony along with my reasons for the adjustments
19 I recommend the Commission make to the TRC Test.

20 **Q. Do you have any other observations on this issue?**

21 A. Yes. Dominion proposes that costs be allocated jurisdictionally.⁵³ This statement
22 apparently means that costs of DSM measures installed in the Company's Virginia
23 jurisdictional territory would be allocated to its Virginia cost of service. Among the
24 reasons given for this is that "[t]he reductions to energy usage and demand caused by
25 DSM programs will affect the jurisdictional allocation factors." This seems reasonable on
26 its face, but the Commission may wish to assure itself that the allocation factors give
27 Virginia full credit for any power cost savings to the parent company and its affiliates.
28 For example, as with retail tariffs, there may be ratchets in the factor definitions that

⁵² Thomas testimony at 12 to 13.

⁵³ Venable testimony at 19.

1 prevent the flow through to the jurisdictional customers of all the power supply savings
2 accrued as a result of DSM in Virginia.

3
4 **Commission Question No. 9. "What 'class cost responsibility methods [are] used in other**
5 **jurisdictions,' and 'would [it] be in the public interest for the Commonwealth to have a**
6 **similar policy' to other jurisdictions that permit certain customers to be exempt from**
7 **participating in and/or paying for a utility's demand-side management programs?"**

8
9 **Q. What is the essential, or threshold, policy issue underlying Commission Question 9?**

10 A. The essential, or threshold, policy issue underlying Commission question 9 is
11 whether it would be in the public interest for the Commonwealth to permit certain
12 customers to be exempt from participating in or paying for utility demand-side
13 management programs or both. That is a threshold question because, if the answer is
14 "no," then the request for information on class cost responsibility methods used in other
15 jurisdictions that allow such exemptions may be rendered moot.

16 The question of whether it would be in the public interest for the Commonwealth
17 to permit certain customers to be exempt from paying for utility demand- side
18 management programs seems to contemplate a re-examination of the current Virginia
19 policy regarding such exemptions. That current policy, established in House Bill 2506
20 passed by the 2009 General Assembly, mandates exemptions for very large use
21 customers, those whose demand exceeds 10 MW, and allows exemptions for general
22 service customers whose demand exceeds 500 kW subject to criteria the Commission
23 must establish by November 2009.

24 **Q. Would it be in the public interest for the Commonwealth to exempt certain**
25 **customers from paying any electric utility demand-side management program costs**
26 **automatically, or as a matter of general policy?**

27 A. No. It would not be in the public interest for the Commonwealth to exempt certain
28 customers from paying any utility demand- side management program costs
29 automatically or as a matter of general policy. Instead, the general policy should be to
30 require utilities to allocate their DSM program costs among all customers just as they
31 allocate their supply costs among all customers. If exemptions are allowed, they should

1 not be automatic for any category of customers. Instead exemptions should only be
2 granted to a very few customers who submit requests demonstrating efficiency
3 achievements at least equal to those being achieved under utility programs.

4 It would not be in the public interest for the Commonwealth to exempt certain
5 customers from paying any utility demand-side management program costs as a matter of
6 general policy because this results in rates that are not reasonable. The customers who are
7 exempted will still be acquiring electricity, and thus will still be receiving the system
8 benefits of the utility's DSM programs, but will not be paying their share of the costs of
9 the underlying programs. In order to appreciate this inequity one must recognize that, as I
10 discuss above in answering Commission question 8, utility DSM programs are a resource
11 that provide system-wide comparable to supply resources. In fact, as I described earlier,
12 the fact that DSM programs provide benefits to all customers over time provides the
13 policy and ratemaking justification for allowing utilities to recover the costs of those
14 DSM programs in rates. When DSM is properly viewed as a cost-effective resource
15 providing system benefits, it is clear that a particular customer, whether or not that
16 customer has reduced his or her energy use or peak demand, should not be exempt from
17 paying for any DSM program costs. As long as the exempt customer is still acquiring
18 electricity, that customer is still receiving the system benefits of the utility DSM
19 programs year after year over the long term.

20 There is substantial potential for inequity in rates under the current Virginia
21 policy regarding exemptions. The customers eligible for exemptions allowed under this
22 policy represent a significant portion of the annual electricity used in Virginia. For
23 example, Mr. Thomas estimates that these two categories of customers account for over
24 36% of the annual retail electricity sales of Appalachian Power Company in Virginia.⁵⁴

25 Moreover, allowing a customer to be exempt is even *less* in the public interest
26 when that customer does *not* reduce his or her energy use and peak demand to the full
27 extent cost effective under the TRC test, because that failure imposes excess, unnecessary
28 and economically inefficient system-wide costs on the utility and all other ratepayers. To
29 the extent that ratemaking and rate design policies results in those excess system-wide

⁵⁴ Thomas testimony at 10.

1 costs being borne by all or some subset of customers, a similar and additional inequity in
2 rates is created for the long-term, but in opposite direction. As a result, exempt customers
3 of this type not only benefit from system-wide savings created and paid for by others, but
4 also pay less than their share of the system-wide costs that they create.

5 This discussion has focused on the cost of service aspects of system-wide
6 benefits. Of course, the same argument applies to all system-wide benefits. One such
7 system-wide benefit of critical importance is risk reduction for the utility. I discussed that
8 point under Commission question No. 8, above, and explain the risk-avoidance benefits
9 of utility DSM programs further below under "Other Issues."

10 **Q. Might it be in the public interest for the Commonwealth to exempt certain**
11 **customers from paying a portion of utility DSM costs to reflect self-financed**
12 **expenditures on efficiency improvements that meet specific criteria?**

13 A. Under certain conditions, it might be. It may be in the public interest for the
14 Commonwealth to allow certain customers to exempt certain customers from paying a
15 portion of the utility DSM costs charged to them to reflect self-financed expenditures on
16 efficiency improvements that meet specific criteria. Under this approach, a customer is
17 exempted from paying a portion of the DSM costs it would otherwise pay, e.g., the DSM
18 program surcharge applied to its annual usage, equal to the amount it has spent on energy
19 efficiency measures within its facility. This approach has been referred to as "banking" in
20 some states and "opt out" in others. In fact, this is effectively the approach that has been
21 approved in North Carolina.⁵⁵ The minimum requirements for this approach to be in the
22 public interest lies in selecting criteria that require customers who apply for this
23 exemption to demonstrate, subject to independent verification, that they have used their
24 own funds to install efficiency measures that are cost-effective to the same extent and
25 according to the same avoided cost assumptions and cost-effectiveness tests as those used
26 by their utility.

27 **Q. Why is it not in the public interest to simply exempt certain customers from paying**
28 **all of their utility DSM costs after a one-time demonstration of self-financing of**
29 **expenditures on efficiency improvements?**

⁵⁵ N.C. Gen. Stat. § 62-133.8(f)

1 A. Exempting certain customers from paying all of the utility DSM costs otherwise
2 charged to them after a one-time demonstration of self-financing of expenditures on
3 efficiency improvements will lead to unreasonable rates. Utilities incur DSM program
4 costs year after year in order to achieve all cost-effective efficiency reductions. While it
5 may be appropriate to exempt a customer from paying a portion of the DSM costs it
6 would otherwise pay equal to the amount it has spent on energy efficiency measures
7 within its facility, the fact remains that the customer is still acquiring electricity and still
8 receiving the benefits of the utility DSM programs. Moreover, if self-financing is to be
9 allowed, then customers interested in self-financing must continue self-financing of
10 efficiency expenditures until it has implemented all cost-effective measures at its site.

11 **Q. What states that exempt certain customers from paying a portion of utility DSM**
12 **costs to reflect self-financed expenditures on efficiency improvements do you**
13 **consider to have model policies?**

14 A. Oregon, New Mexico, and Utah, for example, all limit the amount of the credit or
15 offset a customer can claim to some capped value which is less than 100% of the amount
16 self-financed.⁵⁶
17

18 III. OTHER ISSUES

19 **Q. Do you have any other recommendations in regard to energy efficiency programs?**

20 A. Yes, I have two. The first highlights the importance of avoiding the creation of
21 lost opportunities in the course of delivering utility energy efficiency programs and
22 explains some of the standards that the Commission should impose to prevent that
23 outcome. The second relates to provision of energy efficiency services to certain hard-to-
24 reach customer groups and explains some of the standards that the Commission should
25 impose to ensure equitable treatment of those customers and to avoid losing out on the
26 efficiency savings available in their homes and businesses.

27 **Q. What is your first additional recommendation?**

⁵⁶ For Oregon, see <http://www.oregon.gov/ENERGY/CONS/SB1149/Business/self-direct.shtml>; for New Mexico, see N.M. Stat. Ann. § 62-17-9 (2007); for Utah, see Pacificorp Electric Service Schedule No. 192. Self Direction Credit.

1 A. The Commission should prohibit the creation of lost opportunities and cream
2 skimming in the design and implementation of utility DSM programs. This
3 recommendation is an essential consideration that flows from the duty to assure least cost
4 service.

5 **Q. Please explain those terms and why you make this recommendation.**

6 A. Utility energy efficiency programs, as for any other utility expenditure or
7 investment, should be prudently managed and deliver least cost service. Two important
8 policies are necessary to ensure that outcome. First, utility energy efficiency programs
9 should be designed and implemented to minimize "lost opportunities." Lost opportunities
10 occur when efficiency measures are not installed when it is most cost-effective to do so
11 (e.g., the construction of a new building or facility, building renovations, and the
12 purchase of new appliances or equipment). Second, programs should be designed and
13 implemented to minimize "cream skimming." Cream skimming occurs when only the
14 most cost-effective efficiency measures are installed, even though additional, higher-cost
15 measures would be cost effective. Cream skimming can lead to lost opportunities,
16 because revisiting a customer to install the remaining measures may involve prohibitive
17 transaction costs.

18 While this is not a program design proceeding, I bring this issue to the
19 Commission's attention because, in my experience, the decision rules adopted by utilities
20 often arbitrarily or erroneously create lost opportunities or base their designs on cream
21 skimming approaches. Some utilities in other jurisdictions have arbitrarily limited the
22 number of compact fluorescent bulbs installed in a given residence, even if there are
23 additional change outs that would have been cost-effective. Once the overhead has been
24 spent to enroll a customer in an audit or custom measure program or otherwise,
25 deliberately omitting any cost effective measure prevents least cost resource acquisition
26 and is, therefore, imprudent management. Lost opportunity measures must be designed,
27 approved and deployed as soon as possible, and then the utility can push for maximum
28 (empirically supported) market penetration of that measure. This is critical because if the
29 utilities wait several years to implement these measures, critical opportunities will be lost.

1 The Commission would be wise to take the precaution of explicitly requiring that
2 utility energy efficiency programs be designed and delivered in a manner that prevents
3 cream skimming or the creation of lost opportunities. I also recommend that the
4 Commission require that utility energy efficiency programs (1) adhere to comprehensive
5 approaches that improve energy efficiency of entire buildings or industrial processes,
6 rather than just address single measures or technologies, and (2) include a full menu of
7 services, including incentives, marketing, training, technical assistance, and education on
8 a number of end use applications (such as lighting, appliances, HVAC systems, and
9 improvements to the building envelope).

10 **Q. What is your second additional recommendation?**

11 A. Equity demands proper treatment of hard-to-reach customers, including those on
12 limited incomes, small businesses, and others. These customers face higher and added
13 barriers to implementing DSM on their own or participating in DSM programs.
14 Specifically, the Commission should require that utility energy efficiency programs (or
15 additional, special programs as needed) be designed and implemented so as to ensure that
16 hard-to-reach customers' needs are met in ways the work for them, not just the average
17 customer. Further, as pointed out by Dominion witness Venable⁵⁷,

18 . . . the Second Enactment Clause of Chapter 603 of the 2008 Acts of Assembly
19 ("House Bill 1523"), which created Chapter 24 of Title 56 of the Va. Code, states:

20 That as part of its 2009 integrated resource plan developed pursuant to this
21 act, each electric utility shall assess governmental, nonprofit, and utility
22 programs in its service territory to assist low income residential customers
23 with energy costs and shall examine, in cooperation with relevant
24 governmental, nonprofit, and private sector stakeholders, options for
25 making any needed changes to such programs. [emphasis added.]

26 **Q. Please explain why you make that recommendation.**

27 A. In my experience, some utility program designs and implementation strategies
28 indicate a lack of sensitivity to this requirement and lead me to spell out in some detail
29 here the policy on hard-to-reach customers, which I recommend the Commission adopt
30 and require utilities to use in their energy efficiency programs. The Commission should
31 also establish goals that are based on potential studies not tainted with such errors.

⁵⁷ Venable testimony at 9.

1 **Q. What do you mean by “hard-to-reach” customers?**

2 A. By hard-to-reach customers I mean:

- 3 1. Residential electricity users who rent their residences from persons other than kin
4 (defined in a manner appropriate to Virginia law and society), trusts operated by
5 and for the benefit of the users, or the users' legal guardians;
- 6 2. Commercial electricity users who rent their business property from persons other
7 than the users' owners, parent companies, subsidiaries of their parent companies,
8 their own subsidiaries, or trusts operated by and for the benefit of the same;
- 9 3. Residential or commercial electricity users who traditionally fail to engage in
10 energy efficiency or demand response programs because of one or more severe
11 barriers beyond those experienced by average residential or commercial
12 customers in a utility's service area.

13 By “barrier,” I mean any physical or non-physical necessity, obligation, condition,
14 constraint, or requisite that obstructs or impedes electricity user participation in energy
15 efficiency or demand response programs. Barriers may include but are not limited to
16 language, physical or mental disability, educational attainment, utility meter type,
17 economic status, property status, or geography.

18 **Q. What policy do you recommend to the Commission in regard to utility energy**
19 **efficiency programs for hard-to-reach customers?**

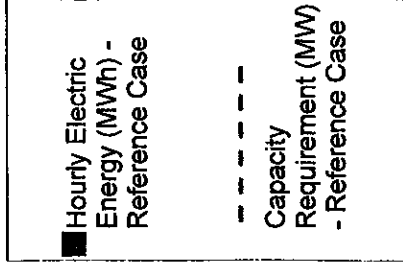
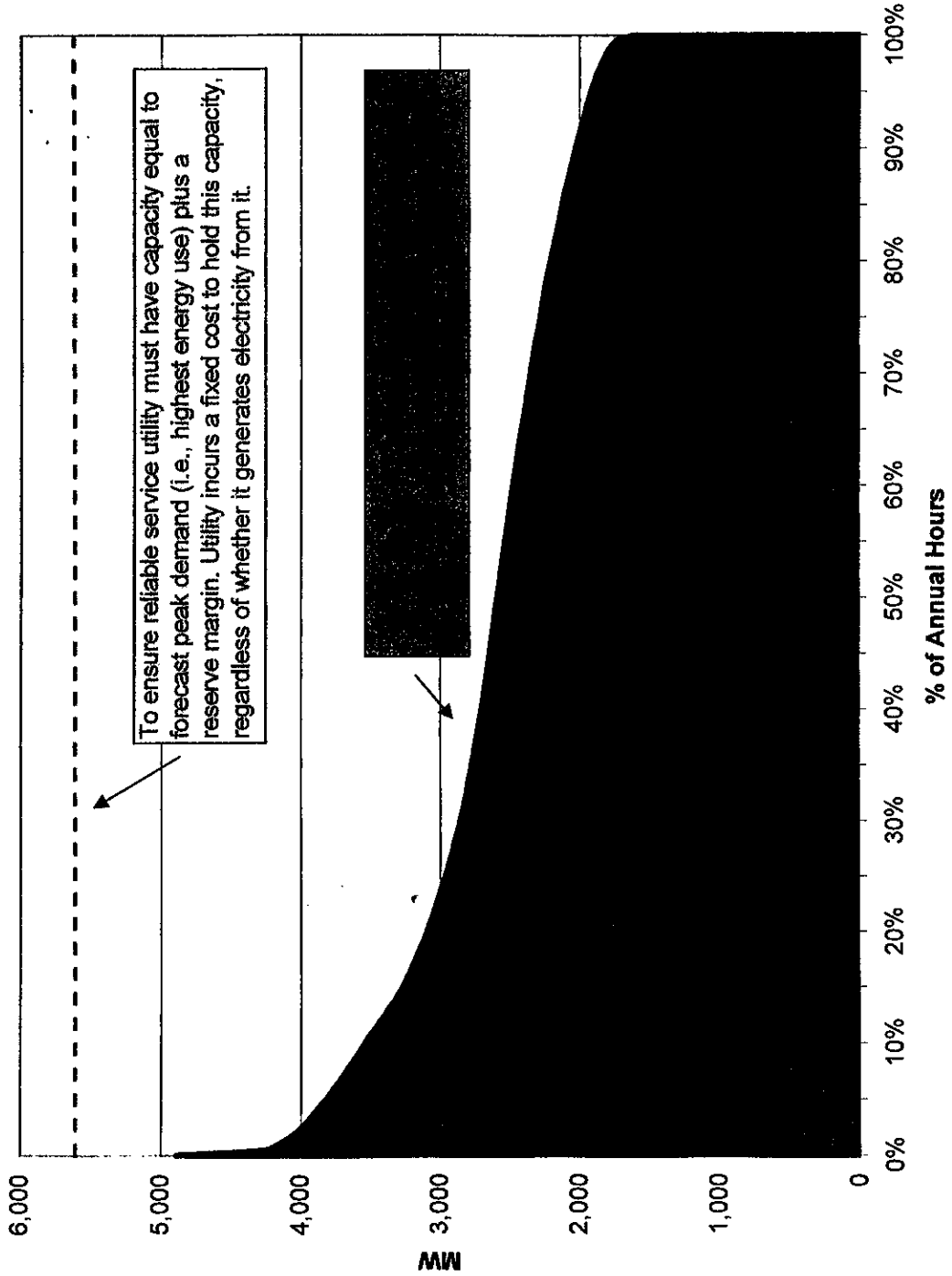
20 A. I recommend that the Commission policy be that utilities are required to address
21 programs for limited-income customers and other hard-to-reach customers so as to assure
22 proportionate energy efficiency programs are deployed in these customer groups despite
23 higher barriers to energy efficiency investments. The Commission may wish to allow
24 programs targeted to low-income or hard-to-reach customers to meet lower threshold
25 cost-effectiveness results than other programs or be enhanced in other ways to ensure that
26 those customers are not left out.

27 **Q. Does this complete your testimony?**

28 A. Yes, at this time.

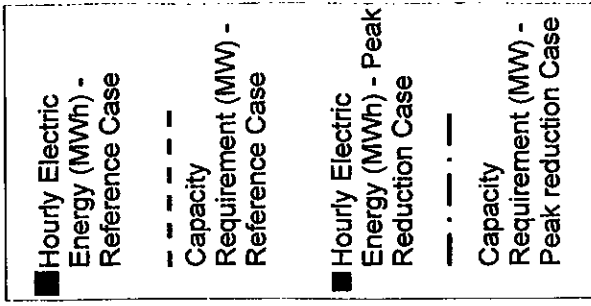
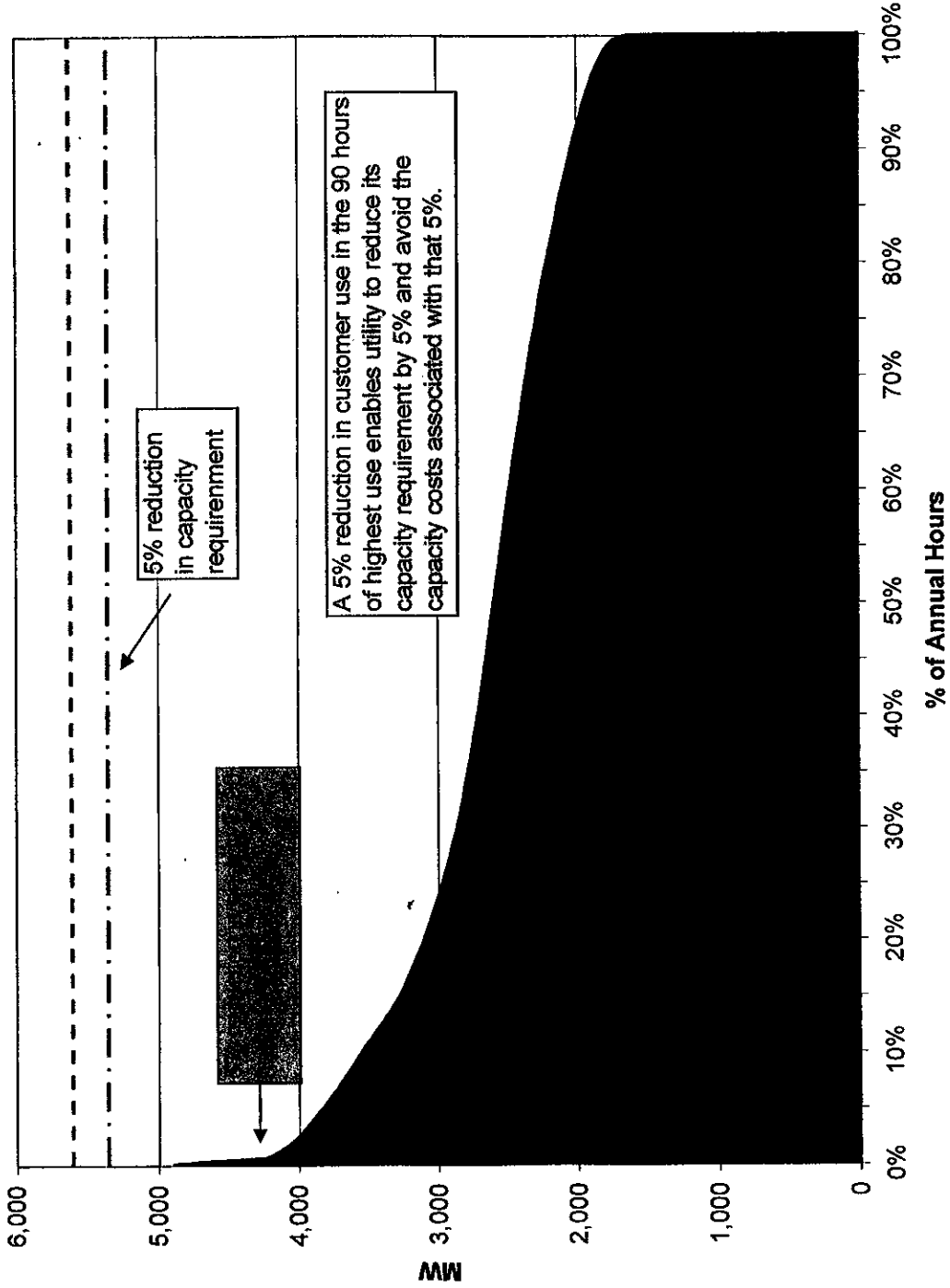
Electric Capacity and Energy for an Illustrative Year and Utility

Reference Case



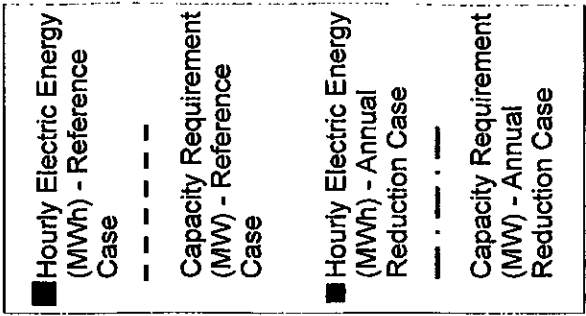
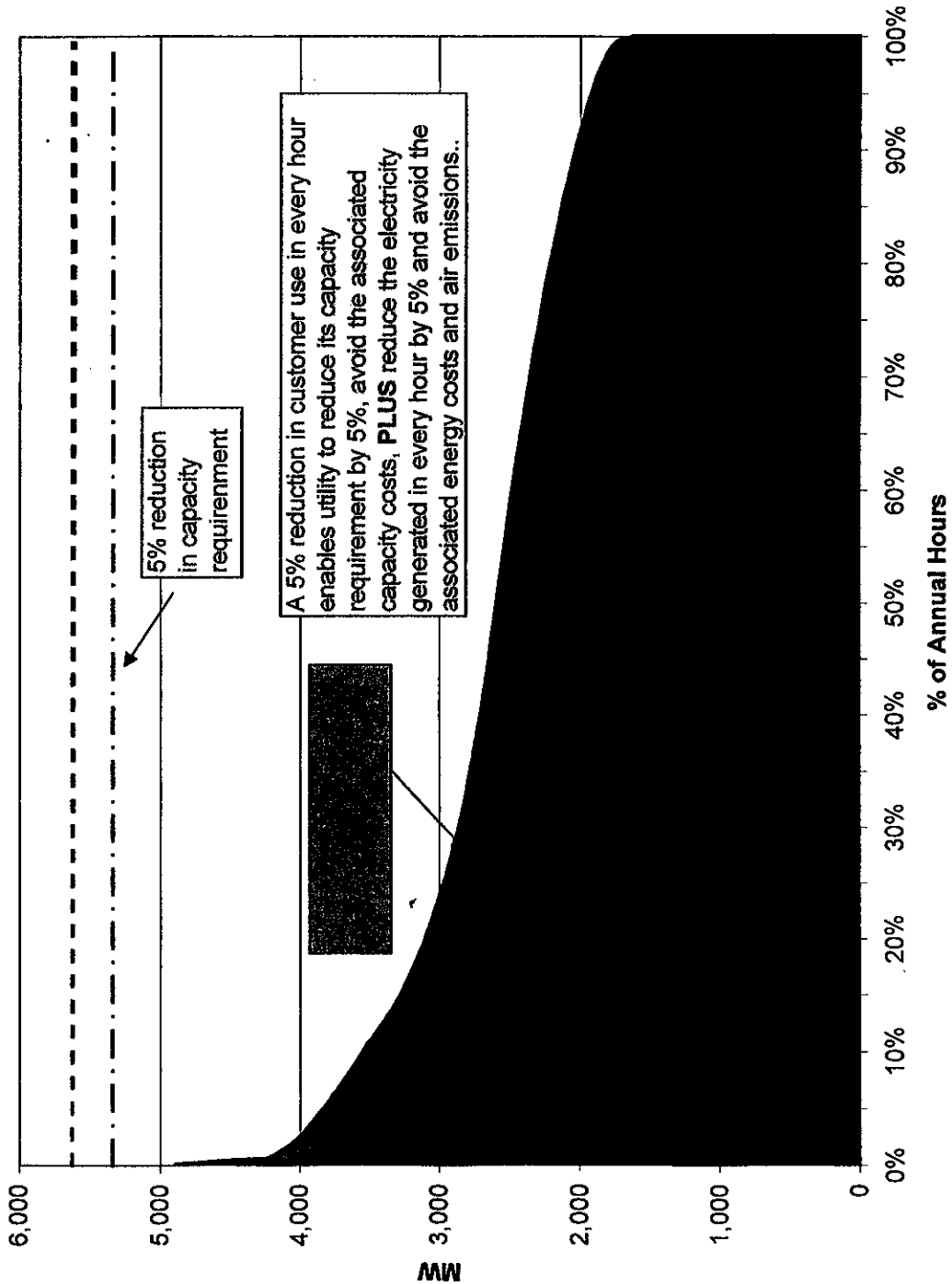
Electric Capacity and Energy for an Illustrative Year and Utility

5% Reduction in Peak Demand



Electric Capacity and Energy for an Illustrative Year and Utility

5% Reduction in Annual Electricity Use



Relative Impacts on Annual Bill of Reductions in Electric Capacity and Energy

			Reduction in Peak Demand in 1% of Hours of Year -5%	Reduction in Every Hour of Year -5%
Customer A				
Load factor	%	17%		
Peak	kw	3		
Annual	kwh	4,500		
Bills	Monthly	\$/month		
	Annual	\$/year	\$ 47	
			\$ 564	
Reductions	Peak demand	kw	-0.15	-0.15
	Annual energy	kwh	-13.5	-225.0
Avoided Costs				
Capacity Cost (w reserve margin)		\$/kw - yr	80	
Energy Cost		\$ per kwh	0.08	
Savings	Capacity	\$/year	\$ (12.0)	\$ (12.0)
	Energy	\$/year	\$ (1.1)	\$ (18.0)
	Total	\$/year	\$ (13)	\$ (30)
	Impact		\$ 564	\$ (13)
				-2.3%
				-5.3%
Customer B				
Load factor	%	46%		
Peak	kw	3		
Annual	kwh	12,000		
Bills	Monthly	\$/month	114	
	Annual	\$/year	\$ 1,368	
Peak reduction	kw		-0.15	-0.15
Annual reduction	kwh		-13.5	-600.0
Capacity Cost (w reserve margin)		\$/kw - yr	80	
Energy Cost		\$ per kwh	0.08	
Capacity Cost		\$/year	\$ (12.0)	\$ (12.0)
Energy Cost		\$/year	\$ (1.1)	\$ (48.0)
Total		\$/year	\$ 1,368	\$ (60)
	Impact		\$ 1,368	\$ (60)
				-1.0%
				-4.4%

Usage data for customers from *Typical Bills and Average Rates Report*, Edison Electric Institute, Winter 2006.
Avoided costs of capacity and energy are assumptions for illustrative purposes

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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Ex Parte: In the matter of determining cost-) CASE # PUE-2009-00023
effective energy conservation ... Chapter)
752 and 855 of the 2009 Acts of the)
Virginia General Assembly)

Submission of Testimony, Exhibits and Supporting Legal Brief on Behalf of Respondent
Robert Vanderhye

As provided by paragraph (9) on page 9 of the Commission's Order of April 30, 2009 in this proceeding, Respondent Robert Vanderhye hereby presents this Legal Brief, as well as the Testimony of Robert Jackson and Exhibits A & B. This brief and accompanying testimony and exhibits are limited to procedures for conservation and peak load reduction for the residential sector. While this brief will deal, to the extent relevant, with each of the specific points 1-9 on pages 3 & 4 raised in the April 30 Order, the most basic question addressed is how can the goal set forth in The Third Enactment Clause of SB 1416/HB 3068 passed by the General Assembly in April, 2007 be achieved in the simplest and most cost effective manner possible. That goal is stated as follows:

“That it is in the public interest, and is consistent with the energy policy goals in § 67-102 of the Code of Virginia, to promote cost-effective conservation of energy through fair and effective demand side management, conservation, energy efficiency, and load management programs, including consumer education. These programs may include activities by electric utilities, public or private organizations, or both electric utilities and public or private organizations. The Commonwealth shall have a stated goal of reducing the consumption of electric energy by retail customers through the implementation of such programs by the year 2022 by an amount equal to ten percent of the amount of electric energy consumed by retail customers in 2006.” (emphasis added)

The question is not really if it is possible to reach the goal, but what is the quickest and easiest way to achieve it. On December 14, 2007 this Commission provided a report (Senate Document No. 17, 2007) to the Governor and General Assembly which

concluded that this goal is achievable. The Virginia Energy Plan¹ estimates that by 2016 it is possible and cost effective for Virginia to reduce peak demand by 17% from 2006 levels. A May, 2007 report² from Summit Blue Consulting estimated that by 2017 Virginia's consumption of electricity could be reduced by 10% and its peak demand by 17%. In 2005 and 2006, respectively (the last years for which statistics are available), per capita Virginians used 18% more electricity and 28% more total energy than residents of the adjacent state of Maryland, 16.5% more electricity than the average American, twice as much electricity as the average Californian, and 63% more total energy than the average Rhode Islander.³ In Dominion Virginia Power's (DVP) June 30, 2009 submission, it stated not only that it could meet the goal, but that it intended to (Venable, pages 5-6).

The conservation goals in the residential sector are most easily and cost effectively met by implementing an inclining block rate schedule for all Virginia utilities

As the testimony of Mr. Jackson, Exhibits A & B thereto, and all materials referenced therein, make clear, it is possible to reduce consumption of electricity by up to 3% the first year, up to 6% in a few years, and up to 20% in the long term, simply by providing a well designed inclining block rate schedule (Jackson, page 10, line 28 – page 11, line 10; Exhibit A, p. 22, 1st col., p. 26, 3rd col.). An inclining block rate schedule (also called inverted, ascending, or increasing block rate, or tiered rate) requires those who use more energy to pay more for the marginal units used. For optimum results such a schedule should have at least three tiers with significant increases from the initial tier to the tail tier, and there must be worthwhile public education.

Reductions in peak load are even greater for many reasons, including that the largest residential users of electricity are particularly sensitive to rate structure changes and use proportionally more energy at the time of system peak than do small users. (Jackson, page 5, lines 12-13; page 5, line 29 – page 6, line 2; page 6, lines 19-24; page 7, lines 19-23; page 9, lines 8-12)

¹ State of Virginia. *The Virginia Energy Plan 2007*. Sept., 2007. Table 2-4, page 40.

² Summit Blue. *Conservation And Demand Response Opportunities In Virginia*, prepared by the Piedmont Environmental Council.

³ U. S. *Per Capita Electricity Use by State in 2005 and Energy Consumption by Source and Total Consumption per Capita, Ranked by State, 2006*.

The three investor owned utilities in Virginia, DVP, Appalachian Power (APCO), and Old Dominion Power (ODP), presently do not have any at all, or any significant, inclining block rate schedules. The present basic residential rate schedules for these Virginia utilities are⁴:

DVP – Basic customer charge of \$7; Transmission charge for first 800 kWh of 2.233¢, over 800 kWh 1.26¢; supply charge for October-May first 800 kWh 4.073¢, over 800 kWh 3.205¢; for June-September first 800 kWh 4.073¢, over 800 kWh 6.051¢.

APCO – Basic customer charge of \$8.40; total for generation and distribution a flat rate of 5.637¢.

ODP – Basic customer charge of \$7.41, total for generation and distribution for the first 1500 kWh 4.942¢, over 1500 kWh 4.226¢.

Thus the ODP rate is a declining rate, the APCO rate is a flat rate, and the DVP rate is a significantly declining rate for 8 months and insignificantly (only a 5% increase) inclining for 4 months. All have a high basic customer charge. Thus the present rates, including high customer charges, clearly discourage conservation.

Of particular significance is the departure of the basic customer charge from the mandates provided in VA §67-101: “2. Managing the rate of consumption of existing energy resources in relation to economic growth....4. Using energy resources more efficiently; 5. Facilitating conservation; ... 10. Developing energy resources and facilities in a manner that does not impose a disproportionate adverse impact on economically disadvantaged and minority communities.” High basic customer charges minimize the ability to conserve and impose a disproportionate adverse impact on economically disadvantaged communities, regardless of what rate structure is used, and the first step toward reaching residential conservation goals is to reduce the basic customer charge to a bare minimum. There appears to be little justification for a basic customer charge over \$5/month. (See Jackson, page 7, lines 7-17, page 10, lines 16-27).

Providing an inclining block rate schedule is certainly the simplest way to maximize conservation while minimizing adverse impact on economically disadvantaged communities since it does not require (although it is enhanced by) the purchase of any equipment. It requires education to be most effective, but any effective system or

⁴ Monthly, per kWh as of April, 2009, not considering the fuel factor or any application for rate increase.

program will require education, and consumers are already used to dealing with varying rate structures in normal life. All that an inclining block rate schedule really requires is the will to implement it.

Of course the fact that an inclining block rate schedule has not been used in Virginia before is absolutely no reason not to implement it immediately now. There is no real reason for the present rate structures considering the present conservation goals of the General Assembly. For example, the DVP cutoff of 800 kWh was implemented in 1981 and the documents indicating the reason why are no longer in existence. If it had something to do with basic electrical use then it no longer has any applicability now, 28 years later, according to statistics and information from the Federal Government (Jackson, page 10, lines 1-15; Exhibit B).

The use of the rate structure to promote conservation was recognized as potentially very useful by the SCC at least as early as 1992 in PUE-1990-00070 (see Jackson, page 3, lines 8-12). The trend across North America is to utilize the rate structure most effectively for conservation by implementing inclining block rate schedules for residential customers. A March 2008 finding by the Kansas Corporation Commission (KCC) is representative of the way many state regulatory commissions look upon inclining block rate schedules at the present time. The KCC found "Rate design is one of a number of factors that contribute to the success of energy efficiency programs", and that "Certainly one would expect higher rates to spur energy efficiency adoption and that appears to be the case for three of the four example states" (three states the KCC studied had inclining block rate schedules, the 4th did not).

A change to an inclining block rate structure is not "revolutionary", but rather was first utilized significantly for electricity in 1978 pursuant to the Public Utility Regulatory Policies Act [16 USC §2621(d)(2)]. In the last decade it has been adopted by numerous state utility commissions around the country. For example Florida, New Hampshire, Vermont, and California, all users of significantly less electricity (and total energy) per capita than Virginia, have inclining block rate schedules for all investor-own utilities (except for one in Florida). There are more than a dozen utilities around the country that have at least two level inclining block rates all year round, and there are at least another nine utilities that have at least three level inclining block rates all year round. According

to a recent survey by B. C. Hydro of 61 U. S. utilities about 1/3rd had inclining block rates, and B. C. Hydro itself successfully lobbied for the adoption of an inclining block rate schedule in 2008. (Jackson, page 6, lines 12-18; page 8, lines 13-20)

The inclining block rate structure not only encourages conservation but when done properly ensures that the poorest and most energy conscious residential customers do not have to subsidize wealthier and less energy conscious ones. (That is, it eliminates or minimizes presently existing large cross-subsidies, and minimizes the "welfare cost".) This is particularly important at this time in our nation's and Commonwealth's history. It is inconceivable that those out of work, with only part-time employment, or in low-paying jobs with little room for advancement and no prospect for a pay raise (that is the "economically disadvantaged...communities"), can even pay the present rates, let alone the increased rates coming in the near future. While in the days before foreign wars over energy resources, legislative mandates for energy efficiency, climate change, and expensive energy, the present declining block rate and flat rate schedules may have been acceptable, they no longer make sense.

A three-or-more tier inclining block rate structure has other advantages aside from a potential 20% consumption and >20% peak load reduction, and elimination of large cross-subsidies. 1) It allows customers to have a much higher level of control than they have had in the past. They can actually do something more significant about their increasing utility bills if they choose. 2) The implementation of an inclining block rate structure at the present time in advance of smart meters (AMI), wide spread time-of-use (TOU) and critical peak pricing (CPP) rates, and other DSM programs, will provide Virginia utilities with valuable customer information and condition customers to upcoming changes that have the ability to even more significantly reduce consumption and/or peak load. It will do this without having to make any changes to present plans for implementation of DSM programs since it is not inconsistent with those programs, and in fact AMI would enhance the effectiveness of an inclining block rate structure. 3) Where the long run marginal cost of energy significantly exceeds the current average cost, an inclining block rate structure can be expected to be successful in reducing a utility's marginal costs, and therefore minimize the need for rate increases in the future. (4) It will result in lower bills for small users (who typically have lower incomes – Exhibit B),

leading to lower bad debt expense, which is a system cost paid by all customers. (5) It will encourage renewable energy installation by home owners (especially solar hot water heaters and photovoltaic panels) since the home renewable energy units will be saving the customers the higher marginal amounts rather than average or declining amounts. (Jackson, page 4, line 16 - page 5, line 15)

An inclining block rate schedule will not in any way adversely affect the Virginia utilities since it is a simple matter to structure the rate schedule so that the utilities obtain essentially the same revenue as they would under their present declining and flat rate schedules. Also, if desired, an inclining block rate schedule can easily be designed so that the median customer pays essentially the same under a new rate schedule as that customer would pay under an old rate schedule.

In order to be most effective the inclining block rate schedule should have three-five tiers, and the first tier must encompass basic household usage. Using information from the Federal Government (Exhibit B; Jackson page 10, lines 2-13) the initial block should go up to about 500-600 kWh per month. This would allow “economically disadvantaged community” customers to be able to live effectively while still providing a price point to encourage conservation.

The inclining block rate schedule can be especially effective with large residential customers in Virginia⁵ since there are many who can easily reduce consumption significantly, including by purchasing Energy Star appliances. All they need is the incentive to do so. For example according to information available from the Governor’s office studying proposed changes in the electricity consumption tax, over 13% of the monthly residential utility bills issued by DVP in 2007 were to customers using more than 3000 kWh per month, that is about three times the average. There were some residential customers who actually used more than 50,000 kWh per month! It is inconceivable that those residential users should be subsidized by poor and energy conscious customers, especially where the marginal costs of electricity can be expected to increase significantly in the future.

Here is a rough example of one form a well designed inclining block rate schedule might take for a fictitious utility (FU) using numbers easy to manipulate:

⁵ This is true in general – see Exhibit A, p. 25, 3rd col.

Assume that FU has 4000 customers. A. 1500 of FU's customers use less than 600 kWh/mo, with an average of 500 kWh. B. 1500 customers use between 601-1200 kWh/mo, with an average of about 800 kWh. C. 500 use between 1201-2000 kWh/mo. with an average of about 1500 kWh. D. 500 use >2000 kWh/mo. with an average of about 4200 kWh. FU thus sells a total of about 4,800,000 kWh/mo, an average of about 1200 kWh per customer. Assume a flat rate of 10¢/kWh, giving FU revenue of about \$480,000/month.

An inclining block rate that would give FU almost the same revenue would be 8.0¢/kWh for 0-600 kWh, 11¢/kWh for 601-1200 kWh, 12¢/kWh for 1201-2000 kWh, and 13.5¢/kWh for >2000 kWh. This results in monthly revenue of about \$481,500 if there is no change in consumption. The average user of 1200 kWh would pay about \$6/mo. different under these scenarios. If the assumption is made that for the first year there would be about a 1.0% decrease in consumption (which would occur exclusively in Groups B-D), then FU's monthly income would be essentially identical to that under the flat rate.⁶ All customers using more than 600 kWh would have the incentive to reduce consumption since the marginal rate would be higher than it was before.⁷

If there were a basic customer charge of \$5, then the effective rate of someone using 600 kWh would not be 8.0¢/kWh, but would be 8.83¢/kWh, an increase of .83¢/kWh; whereas the effective rate for someone using 2500 kWh would increase by only .2¢/kWh. Thus the higher the basic customer charge, the lower the incentive to save because of diminishing differences between the effective rates.

While the inclining block rate schedule alone could likely achieve the desired goal, there is no reason to stop there

By adding in-home displays – which presently cost about \$100-\$300 per household⁸ – the maximum levels of conservation could be achieved. According to a

⁶ If consumption did not decline, the extra money obtained by the utility would go toward supporting DSM programs, such as low income refrigerator replacement. If the reduction in consumption were greater, during the next rate period the tail rate would be adjusted upward to accommodate that decline, and any other expected decrease in consumption, e. g. adjust the tail rate to 14¢/kWh.

⁷ Obviously this is a crude example only, and the specifics could be massaged in any way necessary to achieve any ultimate goals. Other examples, using only a two tier inclining block rate schedule, are provided in Exhibit A, page 26; these examples predict a mean long term drop in consumption of 18.4%.

⁸ According to Karen Blackmore, an analyst at Energy Insights, an affiliate of IT research firm IDC.

May 20, 2009 presentation by The Brattle Group⁹, four utilities using in-home displays alone (without, necessarily, also inclining block rates) were able to average conservation of about 7%, and a savings of 10% is possible according to Energy Insights.

Even though an inclining block rate schedule alone, even without in-home displays, but certainly with them, likely can achieve a consumption and peak reduction of about 20%, combined with dynamic pricing peak reduction can be even greater. The term “dynamic pricing” is the generic term covering time of use (TOU), critical peak pricing (CPP), and other prices that are not fixed during a day or other time period. To achieve optimum results dynamic pricing requires smart meters and actual control by the utilities of at least a certain number of appliances of a certain percentage of customers. According to the May 20, 2009 presentation by The Brattle Group referenced earlier, there were three real world instances where CPP reduced peak load by 50% or more, and four real world instances where TOU reduced peak load by an average of 27%.

Inclining block rates are not only not inconsistent with TOU and CPP, they work well together to optimize conservation goals. (Exhibit A, p. 26, 3rd col., p. 27, 1st col.)

Act Now

The time to act is now. The General Assembly mandates requiring all aspects of Commission proceedings to take into account conservation and energy efficiency, the reality of the environmental, economic, and climate conditions in Virginia and throughout the country, the real cost of peak load capacity necessary to serve the high use customers, and the need to protect the poorest Virginians, all require that the status quo be discarded and that the no-cost, timely and common sense inclining block rate schedule should be adopted as soon as possible.

RESPONSE TO COMMISSION QUESTIONS

1. What is a realistic cost-effective energy conservation target?

A realistic cost-effective energy conservation target is higher than the General Assembly’s goal of a 10% reduction of the 2006 level by 2022. As earlier indicated, this level has already been determined realistic by the Commission and others. In its

⁹ Available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/may202009/a_faruqui-brattle.pdf

submission, DVP has indicated that it not only can comply with the 10% by 2022 goal, but it intends to (Venable, page 5, line 17 – page 6, line 6).

Over the first few years, an inclining block rate schedule alone could be expected to reduce residential energy consumption by about 6% at virtually no cost. Over the long term, that is by 2022, and with proper education and widespread use of in-home displays with an average cost of about \$200, one could realistically expect a reduction in residential energy consumption of about 20%. (Exhibit A; Jackson, page 10, line 28 – page 11, line 10).

Employing the present Virginia utility DSM programs (Jackson page 12, line 17 – page 14, line 10), and an optimized low-income refrigerator replacement program, all of which are cost-effective, it is believed that residential energy consumption could realistically be reduced another 3-5%. This appears to be close to APCO's conclusion (page 5 of Castle's testimony), and that of the 2009 EPRI study "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U. S." discussed on page 6 of the testimony of Venable presented by DVP.¹⁰

Implementing inclining block rates and widespread use of present DSM programs could expect at least a commensurate reduction in peak load, and likely a greater reduction. (Jackson, page 12, lines 12-16).

If AMI, TOU and CPP programs are implemented much larger peak load reductions can be achieved, on the order of 40%, and some (perhaps small) reduction in consumption. However, how cost-effective those programs would be is not known at the present time since the costs of the programs have not been fully developed on a large scale basis. Therefore even though peak load reductions on the order of 40% are realistic, it cannot be said for certain at this time that they are cost-effective.

2. What tests should be used to determine cost-effectiveness?

This question need not even be considered for an inclining block rate schedule since it doesn't cost anything to implement (aside from education).

With respect to industrial and commercial programs, the four standard tests - The Participant Test, The Ratepayer Impact measurement Test, The total Resource Cost Test,

¹⁰ Page 10 of the EPRI study says "Realistic Achievable Potential is 236 TWh or 5% reduction in projected consumption. Maximum Achievable Potential is 382 TWh, or 8% reduction in projected consumption" by 2030.

and The Program Administrator Cost Test - should all be considered for each program, and if 3 out of 4 show the program to be cost effective, it should be considered as such.

For all residential programs, The Participant Test is the most worthwhile since it measures the customer's savings in electricity expenditures compared to the cost of the program to the customer. This is the essence of cost effectiveness. Therefore if The Participant Test and any single other test alone indicate cost-effectiveness, then the program should be considered cost effective.

Residential programs should also be implemented and extensively promoted in the order of their cost-effectiveness under The Participant Test. For example for the programs summarized on page 42 of APCO's Attachment A submitted June 30, 2009, the ranking of the programs would be New Construction, Efficient Products, Low Income¹¹, Retrofit, and Demand Response.

3. How should the Commission define the terms "achievable", "cost-effective", and "be realistically accomplished" as they are used in the statute?

Ultimately the interpretation of the statute is a legal matter for the Commission. However, there is nothing to indicate – at least in the residential context - that any of the three terms should be given any meaning aside from their normal meaning. “Achievable” means can achieve, “cost-effective” means that the monetary, environmental, and health benefits outweigh the costs, and “be realistically accomplished” means that on the basis of experience elsewhere, and/or extrapolation from accepted principles, accomplishment is highly probable.

Whether something meets these criteria may best be determined by evaluating what has been done elsewhere, and by evaluating articles, testimony, and other materials from experts in the field. Utilizing this information, inclining block rate schedules definitely meet all three criteria; they can “achieve” significant conservation, they are “cost-effective” since they cost essentially nothing, and they can surely “realistically accomplish” conservation since they have demonstrated they can do so elsewhere.

¹¹ As listed by APCO. However, since the Low Income program costs the actual participants nothing and clearly benefits all customers it is believed that the value ascribed by APCO is wrong – it should be higher. Compare with Table 1 on page 2 of the ODP testimony of June 30 for its residential Low Income Weatherization program.

4. How should the Commission determine the "public interest" in preparing a "cost-benefit analysis of a demand-side management program"?

The "public interest" is determined by evaluating environmental, health, and monetary impacts on members of the general public, with particular emphasis on economically disadvantaged members of the public. The relevant "public interest" is clearly set forth in statutes. E.g., VA §67-101 illuminates the public interest as follows:

“2. Managing the rate of consumption of existing energy resources in relation to economic growth...4. Using energy resources more efficiently; 5. Facilitating conservation; ... 7. Increasing Virginia's reliance on sources of energy that, compared to traditional energy resources, are less polluting of the Commonwealth's air and waters; 8. Researching the efficacy, cost, and benefits of reducing, avoiding, or sequestering the emissions of greenhouse gases produced in connection with the generation of energy; ... 10. Developing energy resources and facilities in a manner that does not impose a disproportionate adverse impact on economically disadvantaged and minority communities.”

5. What is the potential impact of the generating electric utilities' demand-side management programs on economic development in the Commonwealth?

Residential DSM programs can be expected to have only a positive impact on economic development in the Commonwealth. This is also clearly true for inclining block rate schedules since such schedules will ultimately reduce future rate increases, cause fewer low income customers to default, and actually reduce utility costs for low-income individuals. This will give members of the public, particularly low income individuals, more disposable income which will be used to purchase goods and services in the Commonwealth and thereby spur economic development. Also an inclining block rate schedule will provide incentives for the purchase of Energy Star appliances, more efficient lighting products, and home solar hot water heaters and photovoltaic panels, further spurring economic development in the Commonwealth.

The same is true for most of the DSM programs set forth in the materials submitted by the utilities in this case. For example a low income refrigerator replacement program would require the hiring of individuals to make the necessary assessments, the purchase of Energy Star refrigerators, the delivery of the new refrigerators, and the pickup and recycling of the old refrigerators, clearly spurring economic development within the Commonwealth.

6. What is "the range of consumption and peak load reductions that are potentially achievable by each generating electric utility"?

As far as the residential sector is concerned, there is no reason to believe that any one utility cannot achieve approximately the same reduction in consumption and peak load as the other utilities by using an inclining block rate schedule. While obviously minor differences will ultimately occur just because of the different demographics that the three incumbent utilities serve, there is no reason to believe that all three incumbent utilities cannot achieve a 4-6% reduction in consumption in the first few years, and an 18-20% reduction in consumption by 2022. There is also no reason to believe that peak load reductions would not be greater than the consumption reductions for each of the incumbent utilities.

7. What is the "range of costs that consumers would pay to achieve those reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 15 year period"?

Since there will be no significant cost to the consumers for an inclining block rate schedule, this question is moot for residential customers for this preferred technique. While optimization of the results for an inclining block rate schedule would likely mean purchase by the majority of the consumers of an in-home display unit, with a present average one-time expenditure of about \$200, it is inconceivable that the average customer would not be willing to lay out \$200 (it would be an investment, not cost, because it would result in utility bill savings). This is especially true if the purchase of the in-home display could be "financed" by the utility charging a set monthly fee until paid off.

8. How should the Commission "determine a just and reasonable rate making methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-site management programs"?

The just and reasonable rate making methodology for the residential sector is clearly an inclining block rate schedule. The industrial and commercial sectors should utilize other methodologies to achieve similar goals. In no event, however, should DSM programs for the industrial and commercial sectors add costs to residential customers.

While it is unlikely that any inclining block rate schedule would be effective for the industrial and commercial sectors, like it would be for the residential sector, the industrial and commercial sectors are more easily able to finance the purchase of equipment such as smart meters and computer controls for certain standard equipment in their facilities. Therefore the industrial and commercial sectors could be much more able than the residential sector to quickly implement CPP and TOU programs.

9. What "class cost responsibility methods are used in other jurisdictions" and "would it be in the public interest for the Commonwealth to have a similar policy" to other jurisdictions that permits certain customers to be exempt from participating in and/or paying for a utility's demand-site management program?

With the minor exception of low income-high use (such as from medical conditions that require a respirator and extensive use of air conditioning) customers (Jackson, page 9, lines 4-7), other jurisdictions that effectively use inclining block rate schedules do not allow residential customers to opt-out of the rate schedules. Nor would it make sense to allow residential customers to do so in the Commonwealth.

With respect to presently proposed DSM programs for residential customers, such as provided on pages 64-86 of APCO's Attachment A submitted June 30, the voluntary nature of those programs is essential; customers want to participate because they are highly advantageous. Someone with a non-economic reason (however irrational) not to participate should not be forced to.

With respect to ultimately more sophisticated DSM programs for residential customers, such as CPP and TOU, a voluntary approach should be tried first. Only if the voluntary approach does not achieve the desired goals should participation in the programs be mandatory. If mandatory, there must be a few circumstances where residential customers are allowed to opt-out, such as where all members of a household work nights, or in the previously indicated low-income medical conditions situation.

Conclusion

Early implementation of residential inclining block rate schedules by all Virginia incumbent utilities is requested.

Sincerely,

//s//

Robert A. Vanderhye
801 Ridge Dr.
McLean, VA 22101-1625
703-442-0422 (or sometimes 518-656-3287)
ravar46@yahoo.com

July 16, 2009

Certificate of Service

I hereby certify that I have the 16th day of July, 2009, mailed a true and correct copy of the foregoing, as well as the testimony of Robert Jackson and Exhibits A & B, first class, postage pre-paid, to each of the following:

- C. Meade Browder, Jr., Office of the Attorney General, Division of Consumer Counsel, 900 East Main St., 2nd Floor, Richmond, VA 23219;
 - Office of the General Counsel, State Corporation Commission, 1300 East Main St., 10th Floor, Richmond, VA 23219;
 - W. T. Benson, Piedmont Environmental Council, P O Box 460, Warrenton, VA 20188;
 - Richard D. Gary, Hunton & Williams, 951 East Byrd St., Richmond, VA 23219-4074;
 - M. Renae Carter, Dominion Resources, Inc., Law Dept., P O Box 26532, Richmond, VA 23261; and
 - Kenrick R. Riggs, Stoll, Keenon, Ogden, 200 PNC Plaza, 500 W. Jefferson St., Louisville, KY 40202-2828;
- and have e-mailed a copy to all other participants with an offer to provide a mail copy if requested.

//s//
Robert A. Vanderhye

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

At the relation of the)
STATE CORPORATION COMMISSION)
)
) CASE # PUE-2009-00023
Ex Parte: In the matter of determining cost-)
effective energy conservation ... Chapter)
752 and 855 of the 2009 Acts of the)
Virginia General Assembly)

Testimony of Robert Jackson In Support of Respondent Robert Vanderhye

1 Q. What is your name?

2 A. Robert Jackson.

3 Q. What are your background and qualifications?

4 A. My background and qualifications are on the Appendix sheet at the end of
5 my testimony.

6 Q. On whose behalf are you appearing in this proceeding?

7 A. I am appearing on behalf of the respondent Robert Vanderhye.

8 Q. Do you have any economic interest in the outcome of this proceeding?

9 A. No, except as an incumbent utility customer for my residence in McLean,
10 Virginia.

11 Q. What customer base does your testimony relate to?

12 A. It relates only to residential customers, not industrial or commercial
13 customers, although some principles may have application to small industrial or
14 commercial customers.

15 Q. What is the essence of your testimony?

16 A. When considering demand side management (DSM) programs, the first
17 thing that should be considered is change to the universal rate structure for residential
18 customers since that has the highest probability of achieving desirable levels of
19 conservation with almost no implementation cost.

20 Next, programs should be implemented which have a high probability of
21 achieving conservation without increasing expenses for low or moderate income
22 residential customers.

23 Further, programs should be encouraged that treat conservation purchases by the
24 utility just like investments in power plants, unless the utility can demonstrate that the
25 latter are less costly to residential customers than the former.

26 Finally, the purchase of smart meters or in-home displays should be implemented
27 first for use by time of use (TOU) or critical peak pricing (CPP) customers, but ultimately
28 for virtually all customers to provide the necessary feedback customers need for price
29 signals.

30 Q. Is using the rate structure to achieve conservation a novel concept?

1 A. No, it is an old, well known concept that has been used by other state and
2 federal regulatory agencies and utilities to shape customer behavior and achieve
3 economic and public policy goals. For example, telecommunications companies
4 traditionally charge higher prices during peak periods to provide customers with
5 incentives to move their less valuable calls to off-peak times. Summer electric rates in
6 warmer climates have also often been higher than winter rates in order to encourage
7 conservation and to match prices with costs. Although rate design to optimize
8 conservation has not been effectively implemented in Virginia, in its March 27, 1992
9 order in PUE-1990-00070 the SCC recognized its potential in stating: “Rate design is
10 also a powerful tool which can be used to achieve optimal CLM [conservation and load
11 management] objectives. As staff indicated, it is important to establish appropriate price
12 signals to promote energy efficiency.” Now virtually every Corporation or Utility
13 Commission across the country recognizes the importance of rate design in achieving
14 conservation goals. Representative of this is the March, 2008 finding of the Kansas
15 Corporation Commission in “Dynamic Pricing: A Framing Document” that “Rate design
16 is one of a number of factors that contribute to the success of energy efficiency programs.
17 Along with rate design, it is important to educate customers about their rates so they
18 understand the value of energy efficiency investment decisions.”

19 Q. Does the SCC have the power to use conservation and energy efficiency as
20 objectives in setting rates?

21 A. Not only does it have the power, it has the responsibility.

22 Its power was clearly recognized in the 1990 proceeding mentioned above, in
23 which the SCC quoted from *Secretary of Defense v C & P Telephone*, 217 Va. 149, 152
24 (1976) as follows: “...non-cost factors may be considered by he Commission in setting
25 rates for various classes of service...to accomplish legitimate regulatory objectives.”

26 It’s responsibility is recognized in numerous laws and directives from the General
27 Assembly, including the law under which this proceeding is being conducted. For
28 example, the Third Enactment Clause of SB 1416/HB 3068 passed by the General
29 Assembly in April, 2007 provided:

30 “That it is in the public interest, and is consistent with the energy policy goals in §
31 67-102 of the Code of Virginia, to promote cost-effective conservation of energy
32 through fair and effective demand side management, conservation, energy

1 efficiency, and load management programs, including consumer education. These
2 programs may include activities by electric utilities, public or private
3 organizations, or both electric utilities and public or private organizations. The
4 Commonwealth shall have a stated goal of reducing the consumption of electric
5 energy by retail customers through the implementation of such programs by the
6 year 2022 by an amount equal to ten percent of the amount of electric energy
7 consumed by retail customers in 2006.”
8

9 Q. Is there a particular rate design that is widely recognized as being able to
10 achieve high levels of conservation with little or no cost to utilities?

11 A. Yes. The rate design considered the most effective and least costly is
12 known as “inclining block rate schedules”. Inclining block rate schedules are also called
13 inverted, ascending, or increasing block rate, or tiered rate. The essence of this rate
14 schedule, regardless of what it is called, is that it requires those who use more energy to
15 pay more for the marginal units used.

16 Q. What advantages do inclining block rate schedules have when
17 conservation and energy efficiency are objectives?

18 A. Among the advantages are:

19 1) It allows customers to have a much higher level of control than they have had
20 in the past. They can actually do something more significant about their increasing utility
21 bills if they choose.

22 2) It ensures that the poorest, who are often low-volume users of electricity, and
23 most energy conscious residential customers don't subsidize wealthier and less energy
24 conscious customers. That is, it eliminates or minimizes presently existing large cross-
25 subsidies, and minimizes the "welfare cost".

26 3) Where - as in Virginia - the long run marginal cost of energy exceeds the
27 current average cost, an inclining block rate structure can be expected to be successful in
28 reducing a utility's marginal costs, and therefore minimizing the need for rate increases in
29 the future.

30 4) It will result in lower bills for small users (many of whom have lower and fixed
31 incomes, such as retirees), leading to lower bad debt expense, which is a system cost paid
32 by all customers.

33 5) It will encourage renewable energy installation by home owners, especially
34 solar hot water heaters and photovoltaic panels, since the home renewable energy units

1 will be saving the customers the higher marginal amounts rather than average or
2 declining amounts. Encouraging the use of renewable energy is also a clear goal of the
3 General Assembly as set forth in VA §67-101 and §67-102.

4 6) The implementation of an inclining block rate structure at the present time in
5 advance of smart meters (AMI), and wide spread use of TOU and CPP programs will
6 provide utilities with valuable customer information and condition customers to
7 upcoming changes that for some customers will have the ability to even more
8 significantly reduce consumption. It will do this without having to make any changes to
9 present plans for implementation of other DSM programs since it is not inconsistent with
10 those programs, and in fact AMI would enhance the effectiveness of an inclining block
11 rate structure.

12 7) Residential inverted block rate schedules are also known to reduce peak load
13 by an even greater proportion than they reduce consumption in general.

14 And, 8) it does not cost the utility any money to implement, except expenditures
15 for educating the public about the new rates and their significance.

16 Q. Are any of the advantages you listed widely recognized?

17 A. Almost all are widely recognized.

18 Q. Can you give some examples?

19 A. Yes. In testimony before the Nova Scotia Utility and Review Board
20 November 24, 2004, Dr. Larry Hughes set forth a general description of inclining block
21 rate schedules and the advantages thereof compared to declining block rate and flat rate
22 schedules. The two main advantages he pointed out are reducing consumption, and
23 reducing or eliminating cross subsidies for customers with low energy consumption and
24 disproportionately lower demand during the system peak.

25 In the Kansas Corporation Commission March, 2008 report discussed above, that
26 Commission recognized that higher marginal rates would spur energy efficiency
27 adoption, and studied four examples states where that was the case including three using
28 inclining block rate schedules.

29 In "Know Your Customers; A Review Of Load Research Data And Economic,
30 Demographic, And Appliance Saturation Characteristics Of California Utility Residential
31 Customers" by Marcus and Ruszovan, December 11, 2007, the authors unequivocally

1 demonstrated that small users use a lesser proportion of peak energy than large users,
2 compared to their average consumption. For example customers using less than 500 kWh
3 per month used 20% of summer energy but only 17% of coincident peak load, yet used
4 24% of the annual residential consumption because they use relatively more power
5 during the winter months.

6 In a report by Dr. Ahmad Farugui of the highly respected The Brattle Group in
7 "Public Utilities Fortnightly", August, 2008, "Inclining Toward Efficiency", the author
8 clearly established that there are both short term and long term price elasticities for
9 electricity. The analysis concluded that properly designed inclining block rates would
10 reduce consumption by a significant amount in just a few years and by an enormous
11 amount in the long term, as well as decreasing customer bills by a substantial percentage.

12 In proposing residential inclining block rate schedules in a rate case, on July 9,
13 2008 British Columbia Hydro and Power Authority (B. C. Hydro) asserted that smart
14 meters are not incompatible with inclining block rate structures, but in fact would
15 enhance them. The utility also demonstrated that it was clear that inclining block rates
16 would facilitate conservation, and that implementing those rates in advance of smart
17 meters and widespread TOU rates would facilitate the latter introduction by providing
18 B.C. Hydro with valuable customer information.

19 In testimony before the Utah Public Service Commission on September 27, 2006,
20 Anthony J. Yankel showed - using both 2000 and 2004 statistics from the utility - that
21 smaller users make a much lower contribution to peak demand than larger users. He
22 concluded that this suggested at least a three tier inclining block rate schedule was
23 necessary in order to provide effective equitable cost-sharing between high users and
24 small users, and that the first tier for monthly consumption should be 0-600 kWh.

25 The testimony of Courtney Waites of Idaho Power Company in an Idaho rate case
26 on June 27, 2006 proposed a tiered rate for both non-summer and summer months
27 because the average non-summer marginal cost had risen more than the average summer
28 marginal cost. On behalf of the utility she maintained that 0-600 kWh per month is the
29 appropriate amount for the first block of energy usage in an inclining block rate structure
30 in order to minimize cross-subsidizes.

1 The direct testimony of Frank Radigan on behalf of the Arizona Corporation
2 Commission Utilities Division Staff, March 14, 2008, in a Tucson Electric Power
3 Company rate proceeding, agreed with the utility that a three tier inclining block rate for
4 residential classes was necessary to encourage conservation and minimize cross subsidies
5 but proposed a higher differential between the initial block and tail block than proposed
6 by the utility.

7 In Pre-Final Direct Testimony before The Public Service Commission of Utah,
8 July 21, 2008, Dr. Richard Collins set forth a very complete discussion of how utility
9 rates should be set and proposed a four tier inclining block rate schedule. He
10 demonstrated that low usage customers were not responsible for the large increase in
11 overall usage in Utah and the corresponding costs placed on the system by the increasing
12 usage. He also asserted the customer charge should not be raised since that is completely
13 unfair to low users and avoids elimination of undesirable cross subsidies otherwise
14 provided by an inclining block rate. In his rebuttal testimony filed September 3, 2008,
15 Dr. Collins demonstrates that the four tier inclining block rate schedule proposed will
16 send proper price signals to encourage customers to reduce or shift their pattern of energy
17 use, and to bring prices closer to marginal costs and to encourage heavy users to curb
18 their electricity use.

19 As one last example, the Prepared Supplemental Testimony of William B. Marcus
20 on behalf of the Arkansas Attorney General, October 31, 2000, provided that in his
21 analysis of a number of utilities he has found that smaller customers and customers living
22 in apartments typically have lower peak load profiles than larger or single-family
23 customers within the residential class.

24 Q. Is there any Federal Government data indicating that low income
25 customers are typically low use customers, and also contribute less to peak demand than
26 high use customers?

27 A. Yes. The Energy Information Administration in Table AP5 entitled
28 "Average Consumption for Home Appliances and Lighting by Fuels Used, 2005 Physical
29 Units per Household" – provided as Exhibit B to my testimony - which is the most recent
30 data, found that the total yearly consumption of electricity by family income groups
31 increased in a straight line progression from 2005 Household Incomes of less than

1 \$10,000 to more than \$100,000. The low was 4,619 kWh for households with less than
2 \$10,000 income and the high was 10,633 kWh for households with more than \$100,000.

3 Q. Are inclining block rates for electricity a new concept?

4 A. Absolutely not. A change to an inclining block rate structure was first
5 utilized significantly for electricity in 1978 pursuant to the Public Utility Regulatory
6 Policies Act [16 USC §2621(d)(2)].

7 Q. Has an inclining block rate structure been adopted by any utility
8 commissions for electricity rates in the U. S.?

9 A. Yes. In the last decade it has been adopted by numerous state utility
10 Commissions around the country. For example Florida, New Hampshire, Vermont, and
11 California, all users of significantly less electricity (and total energy) per capita than
12 Virginia, have year round inclining block rate schedules for all investor-own utilities,
13 except for one in Florida. According to a recent survey of 61 U. S. electric utilities
14 (obviously there are many more utilities than that) done by B. C. Hydro about a third had
15 inclining block rates. There are more than a dozen utilities around the country that have
16 at least two level inclining block rates all year round, and there are at least another nine
17 utilities that have at least three level inclining block rates all year round, and a number of
18 others have at least three tiers in the summer and a flat rate for the rest of the year. Also,
19 a number of electric utilities in Canada, including B. C. Hydro, have all year round
20 inclining block rates with significant price differences between the tiers.

21 Q. Can you give some examples of three or more tier inclining block rate
22 schedules?

23 A. Yes. All of these are kWh per month:

24 Avista in Washington State has the following three tier structure all year round:

25 0-600 kWh, 5.926¢/kWh; 601-1300, 6.895¢; >1300, 8.083¢; basic charge \$5.75

26 The rate structure of Pacific Power in Utah is:

27 0-400 kWh, 7.5292¢/kWh; 401-1000, 8.9416¢; >1000, 11.1216¢; basic charge \$3

28 The rate structure for Longmont Power in Colorado is:

29 0-750 kWh, 5.57¢/kWh; 750-1500, 6.08¢; >1500, 6.78¢; basic charge \$5

30 Q. Are there any disadvantages to inclining block rate schedules?

31 A. The only known disadvantages are:

1 1) In order to be most effective, public education is necessary. However, this
2 same disadvantage exists for almost any program, such as the introduction of a separate
3 charge for electric distribution services, so it is not a unique disadvantage.

4 2) There will be a few low income households that have high electricity usage,
5 such as for some medical conditions which require respirators and continuous air
6 conditioning. However, there are very few of such households and they can be
7 accommodated simply by having a separate low-income-medical-condition rate schedule.

8 3) There will be some large users who have a precipitous increase in their electric
9 bills. However according to all statistics available, the largest users are exactly the type
10 of people who should receive an economic incentive to reduce energy consumption and
11 to purchase the most energy efficient appliances and lighting, therefore they have a large
12 degree of control over their use.

13 Q. How would the average ratepayer be affected by a move to an at least
14 three tier inclining block rate schedule?

15 A. The rates and tiers can be designed so that the average ratepayer would see
16 essentially no change in his/her monthly bill. That is, for people using between about
17 1000-1100 kWh/month the rate can be designed so that there was essentially no change in
18 their monthly electric bills, all other things being equal.

19 Q. How would those using less or more electricity than average be affected?

20 A. Those using significantly less electricity than average would see their
21 monthly bills go down when an at least three tier inclining block rate schedule was
22 implemented, and those using significantly more electricity would see their bills go up.
23 For example, ratepayers using less than 600 kWh/month would see their bills go down
24 significantly, while those using more than 2000 kWh/month would see their bills go up
25 significantly.

26 Q. What should the goals of an inverted rate schedule be?

27 A. The goals should be: 1) to set a lower priced initial block at a level
28 sufficient to accommodate the basic electrical needs of most users; 2) to provide
29 incentives for every one to conserve electricity; and 3) to structure usage blocks and
30 associated rates, appropriately, in order to recover the higher marginal costs of generating
31 electric power to meet higher levels of consumption.

1 Q. What should the initial price block be, and why?

2 A. Based upon the actions of other utility commissions and testimony by
3 other experts in the field, the initial price block should be between 0-500 and 0-600
4 kWh/month since this is the level that is high enough so that it accommodates the basic
5 electrical needs of most users, but also low enough so that it establishes a price point for
6 additional consumption that would give even low level users the incentive to conserve.
7 For example, according to the 2005 Energy Information Administration statistics set forth
8 above, Exhibit B, the average household consumption in the South Atlantic Region
9 (which includes Virginia) for refrigerators, other appliances, and lighting, is 655
10 kWh/month. Also, according to other authoritative sources, including HUD's "*Utility*
11 *Allowance Guidebook*" (as reported in "FSC's Law & Economic Insights", Issue 07-5,
12 September/October 2007), lighting, refrigeration and cooking alone would yield a
13 consumption of about 300 kWh/month for a typical household (e. g. a three bedroom
14 apartment). Also, almost all experts that I have seen testimony of, or articles written by,
15 suggest an initial price block between 0-500 and 0-600 kWh/month is best.

16 Q. What level should the basic customer charge be set at in an inclining block
17 rate schedule?

18 A. The basic customer charge - which presently ranges between \$7/month
19 and \$8.40/month for Virginia's incumbent utilities - must be examined very carefully
20 since it is totally non-productive in an inclining block rate scheme. It significantly
21 distorts the goals of an inclining block rate schedule since it provides a negative
22 contribution to the encouragement of conservation. A basic customer charge should be
23 set at a level that recovers only direct costs of maintaining a customer's account and does
24 not contribute to the recovery of other costs incurred in providing electricity to
25 customers. In the three examples I previously gave of utilities in Washington, Utah and
26 Colorado with inclining block rate schedules, the basic customer charges were \$5.75,
27 \$3.00, and \$5.00, respectively, significantly less than the present levels in Virginia.

28 Q. From actions in other jurisdictions, what level of conservation could one
29 expect to see from the implementation of an inclining block rate schedule alone?

30 A. The level of success would depend upon how well designed the price
31 points were, how many tiers it had, how much public education there was, and a number

1 of other factors. However, assuming a well designed schedule and significant public
2 education, according to the highly respected The Brattle Group one could expect savings
3 in the 6% range over the first few years, and a long term savings on the order of 20%.
4 When B. C. Hydro successfully argued for an inclining block rate schedule in its 2008
5 rate application, it estimated a savings in the first year of 1-3%, most likely 1.5%.

6 Q. What is Exhibit A to your testimony?

7 A. That is the August, 2008 article by Dr. Faruqui of The Brattle Group
8 mentioned earlier that discusses electricity price elasticities in the U. S. and estimates the
9 6% - 20% savings discussed above. It also estimates that customer bills could
10 collectively be reduced by as much as 25%.

11 Q. Is the fact that the amount of conservation that can be achieved in the first
12 year is not susceptible of precise prediction a significant drawback to implementation of
13 an inclining block rate?

14 A. No. As established by B. C. Hydro in its 2008 rate case #3698504 there
15 are many other estimates made that are imprecise – such as estimating the fuel factor –
16 and that is not a reason not to implement them. Adjustments are simply made in the next
17 rate case or could even occur in special periodic true-up reviews.

18 Q. Is there a procedure that could be particularly practical in conjunction with
19 other DSM programs?

20 A. Yes, the options are limited only by the imagination, but one that might be
21 effective would be to estimate an optimistic reduction in consumption when designing the
22 first inclining block rate schedule – say a 2.5% reduction for the first year. If the
23 reduction is less than that, the amount of additional revenue the utility collected would
24 then be used in the subsequent rate period to fund another DSM program, such as buying
25 in-home displays for any customer who requested one, or giving a new Energy Star
26 refrigerator to replace any primary refrigerator of any customer with a unit more than 15
27 years old. The key is for the Commission to use any “excess revenues” stemming from
28 higher than projected demand to fund more energy conservation programs, at least until
29 the General Assembly’s conservation goals have been met.

1 Q. From available information, what percentage of the goal of a 10%
2 reduction in electrical usage from 2006 levels by 2022 could one expect there to be from
3 the implementation of a well designed inclining block rate schedule alone?

4 A. For the residential sector one could expect the entire goal to be achieved
5 based upon experience in other jurisdictions.

6 Q. How cost effective would that result be?

7 A. Considering that the results could be achieved with only expenditures for
8 education, or - if a higher level of success were desired - the purchase of in-home
9 displays for customers who wanted them to help gauge usage, it would be more cost
10 effective than any of the programs mentioned in the testimony submitted June 30, 2009
11 by the utilities in this proceeding.

12 Q. What level of peak load reduction could be expected from the
13 implementation of a well designed inclining block rate schedule alone?

14 A. All available information indicates that the peak load reduction likely
15 would be several percent greater than the level of consumption reduction, in other words
16 more than 6% in a few years, and more than 20% over the long term.

17 Q. What other relatively simple DSM programs are there that you believe
18 could significantly advance conservation efforts in a manner clearly in the public
19 interest?

20 A. One is low-income refrigerator replacement. This is a simplified version
21 of the program suggested by Appalachian Power Co. in its submission of June 30, 2009
22 known as "Residential Low Income Program" discussed on pages 71-76 of Attachment A
23 of its submission. The program involves four steps, identifying households with incomes
24 200% of poverty level or lower, identifying the only refrigerator in the household as one
25 that has substandard efficiency or is more than 15 years old, replacing the refrigerator
26 with a roughly similarly sized (or lower capacity if the refrigerator is over-sized for that
27 household) new Energy Star refrigerator, and recycling the old refrigerator.

28 Q. Has such a program ever been successfully implemented?

29 A. Yes, many such programs have. One example is New York Power
30 Authority in NYC which will ultimately replace 180,000 refrigerators in low income
31 households with electric-bill savings of more than \$6,000,000 and conservation of

1 63,000,000 kWh over the nine year life of the program. Another is the Cinergy program
2 in Cincinnati, which has used a simplified model to determine candidates for replacement
3 that has minimized program costs. Using two standard sizes of Energy Star replacement
4 refrigerators (18 cubic feet and 21 cubic feet) average savings of 1,230 kWh/year per
5 refrigerator have been achieved. This is like the utility building a pollution free small
6 power plant for each such customer. The Cinergy program also identified another
7 significant benefit in addition to conservation. It found that many older refrigerators
8 were not power factor corrected which contributed to increased line losses at times of
9 system peak demand, making the entire serving grid more reliable when the older
10 refrigerators were replaced.

11 Q. Is there another version of this program that could have wider
12 applicability?

13 A. Yes, the program could be offered to any customer with a single working
14 refrigerator more than 15 years old. For those with household incomes more than 200%
15 above the poverty level instead of just giving them the new refrigerator, they could be
16 charged (directly on their bill) a monthly amount less than their anticipated savings of
17 electricity, with the balance due if the refrigerator (or dwelling containing it) were sold.

18 Q. What is your view of the other residential programs proposed by
19 Appalachian Power (ApCO) and Old Dominion Power (ODP) in testimony in this
20 proceeding, and discussed in the Dominion Virginia Power (DVP) portion of the Energy
21 Conservation Efforts of Virginia's Investor-Owned Public Utilities In 2008 report?

22 A. The vast majority of them appear highly desirable, cost effective, and in
23 the public interest and should be strongly encouraged by the SCC. In particular the
24 ApCO programs known as Residential Efficient Products, Residential Home Retrofit,
25 Residential Low Income, and Residential New Construction; the ODP programs known
26 as Residential Conservation, Residential Load Management, Residential Low Income
27 Weatherization, Residential High Efficiency Lighting, and Residential New Construction;
28 and the DVP programs Residential Power Cost Display Monitor, Residential Energy Star
29 New Homes, Residential Low Income Energy Audit, and Residential High Efficiency
30 Heat Pump, are particularly cost effective.

1 Q. Is there any way to enhance the incentive of the utilities to more
2 vigorously promote and deploy desirable conservation programs?

3 A. Yes, where appropriate, the utility can be allowed to add the cost of these
4 programs to its rate base and review requirement. For example, for the refrigerator
5 replacement program proposed, the utility should be able to treat the true cost of the
6 refrigerators it gives away just like a new power plant for a predetermined period, and
7 add it to the rate base for that period. This would likely encourage the utility to expand
8 the program to all non-profit organizations throughout the state including schools,
9 prisons, and government offices, wherever a true cost-effective conservation benefit
10 could be achieved.

11 Q. Are there some DSM programs that are not particularly worthwhile?

12 A. The residential refrigerator recycling/turn-in programs of both ApCO and
13 DVP do not appear to be cost-effective, and would likely become moot if a proper
14 education program were included with an inclining block rate schedule.

15 Q. Does this conclude your direct testimony?

16 A. Yes, it does.

17

1 APPENDIX- BACKGROUND AND QUALIFICATIONS OF ROBERT JACKSON

2 I am an attorney with the McLean law firm General Counsel PC and also maintain
3 a separate utility law practice in Washington, D.C. My business address is: 1725 I
4 Street, NW, Suite 300, Washington, D.C. 20006. I am also a resident of McLean, VA.

5 I have a B.A. (summa cum laude) degree from the University of St. Thomas, in
6 St. Paul, Minnesota, and a J.D. (cum laude) degree from the University of Minnesota,
7 Minneapolis, Minnesota. I am admitted to practice law in Iowa, Minnesota, Nebraska
8 and the District of Columbia.

9 I have practiced public utility law since 1977. I worked as an attorney for
10 Northwestern Bell Telephone Company (NWB) in Omaha, Nebraska and Des Moines,
11 Iowa. In 1984, I transferred to NWB's parent company, US West, in Washington, D.C.,
12 where I held the titles: Attorney-Federal Relations, Director & Senior Counsel,
13 Managing Counsel & Director, and Executive Director. In 1998, I joined the Washington
14 office of Arter & Hadden LLP as Of Counsel in the Communications and Media Practice
15 Group. I moved to Reed Smith LLP in 2001 as Of Counsel in the Government Services
16 and Communications Practice Group. In May 2005, I opened my own law practice in
17 Washington, D.C. Last summer, I affiliated with General Counsel PC in McLean.

18 I was the chief draftsman for the utility industry for a major revision of Iowa's
19 public utility regulation law, working with attorneys and lobbyists for electric, gas and
20 telephone companies. I have spent much of my career working with utility pricing and
21 costing issues with both state and federal regulatory agencies.

22 In addition, to working as in-house counsel and a telecommunications executive, I
23 have represented and counseled utilities, including electric utilities and telephone
24 companies, in private practice.

25 While at NWB, I advised marketing groups on cost and pricing issues and
26 handled rate design issues in a number of regulatory proceedings before state utility
27 commissions. For example, I obtained regulatory approvals for the introduction of local
28 measured service and carrier access charges in Iowa. I have written and reviewed
29 testimony for state utility commission cases. I have cross-examined and defended
30 witnesses in rate hearings; testified at public hearings on proposed agency rules; written

1 countless utility pricing-related advocacy documents and been involved in several court
2 appeals.

3 While in Des Moines, I also was heavily involved in many utility rulemaking
4 proceedings that often affected various types of Iowa utilities.

5 When working for U.S. West, I was responsible for its then \$2.3 billion annual
6 interstate access charge revenues before the FCC, during the late 1980s and early 1990s.
7 At that time, I was heavily involved in several major rate design proceedings at the FCC,
8 including the restructuring of prices for WATS access lines (ending the traffic sensitive
9 recovery of non-traffic sensitive costs), the exiting of the largest telephone companies
10 from the mandatory access charge pool and concomitant restricting of end user charges,
11 the first successful discounting of interstate access charges for FTS 2000, and the
12 beginning of Price Cap regulation. I am familiar with various economic and public
13 policy theories underlying utility rates, including incremental and embedded costs, value
14 of service pricing, and Ramsey Pricing.

15 Also, while at US West, I served as a regulatory consultant to PCS PrimeCo,
16 which is now part of Verizon Wireless. Finally, I handled various cable television
17 regulatory matters before the FCC, for US West's then affiliate, MediaOne.

18 In private practice I also have represented and counseled numerous carriers (rural
19 telephone companies, competitive local exchange carriers, long distance carriers and
20 wireless carriers) on cost and rate issues and assisted a number of carriers in complying
21 with the FCC's detariffing orders. I have negotiated interconnection agreements for
22 carriers and various utility agreements (electric, gas and telecommunications), with price
23 impacts, for numerous real estate developers. I have assisted carriers with Universal
24 Service Fund (USF) compliance matters and represented carriers on inter-carrier
25 compensation and USF reform. I have also represented and advised electric utility
26 companies on telecommunications issues.

27 I have been interviewed by national and trade press on utility issues and have
28 written related op-ed pieces.

29 I have testified in the District of Columbia Superior Court as an expert witness on
30 jurisdictional aspects of utility pricing.

1 I previously served as chair of the McLean Citizens Association's (MCA) Budget
2 & Taxation Committee for three years, where I led our annual analysis of Fairfax
3 County's operational and school budgets and testified to the Fairfax County Board of
4 Supervisors on its proposed budget and tax rates. In 2007, I advised three candidates for
5 local offices (one Democrat, one Republican, and one Independent) on Fairfax County
6 budget and taxation issues. Today I serve as president of the MCA and have testified
7 before the Fairfax County Planning Commission on the economic aspects for existing
8 residents of the proposed rezoning of Tysons Corner.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

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 Ex Parte: In the matter of determining cost-) CASE # PUE-2009-00023
 effective energy conservation ... Chapter)
 752 and 855 of the 2009 Acts of the)
 Virginia General Assembly)

Submission of Testimony, Exhibits and Supporting Legal Brief on Behalf of Respondent
David Prezioso, Vice President Strategic Business Development Ice Energy Inc,
Headquarters' Windsor CO.

My name is David Prezioso. I am the Vice President of Strategic Business Development for Ice Energy, Windsor, Colorado. My office is located in Atlanta, Ga. I am responsible for the utility market for Ice Energy in the south eastern US.

I have over 30 years of experience working in the utility market. I started my career as an instrument apprentice, then journeyman for Diamond Shamrock Corp of Fairport Harbor, Ohio in the mid 1970's. I worked on large utility boilers and turbines in respect to coal power plants. After that I worked for Honeywell in the industrial control sector but was focused on utilities and production of electricity through traditional coal, gas, nuclear generation as well as co generation and other advanced technologies. I did my undergraduate work at Ohio State University and received my degree in Electrical Engineering from La Salle University and later completed my Masters degree in Business Management from La Salle. I worked at as Regional Operations Manager for Honeywell and later Leeds & Northrup Corporation (L&N) of North Wales, Pa. where the focus was on power generation. I have held positions of operations management, regional manager of sales and operations, director of services and acted as internal consultant to the president of Honeywell's process control division for a number of years.

In summary my experience in the utility business is both hands on and in various management positions that spanned across all technologies developed for the last 40 years.

The testimony I am providing today is grounded on expert field experience and will provide a transformational view of how power companies can redeploy existing assets to reduce cost and avoid building out additional infrastructure, all while reducing emissions,

improving reliability and comfort to the end users while enabling the integration of intermittent renewable resources on the grid today by using a new transformational technology called the "Ice Bear" manufactured by Ice Energy.

Issues related to cost effectiveness studies with in the utilities today.

1) In the past utilities used an antiquated methodology to protect consumer rates regarding energy efficiency called the Rate Impact Measure (RIM) cost-effectiveness test as the ultimate screen for energy efficiency. The problem with this test it only measures short term rate impacts to ratepayers rather than long term economic benefit to the whole body of ratepayers from an energy efficiency measure. It also prohibits the utility from introducing new technologies to reduce operating cost and reducing dependency on carbon fuels as most new technologies initial cost are higher than traditional methods of generating and delivering power but their long term or life cost are much less costly than assets currently used in generating and delivering power.

2) A more appropriate analysis to determine whether an asset is beneficial to the utility and the rate payers is the Total Resource Cost (TRC) Test. The TRC methodology uses projections of avoided electricity costs (marginal cost) to express benefits in a standard benefit-cost test calculation. Costs represent the incremental cost of the energy efficient equipment and any associated program support costs. The TRC results are expressed either as an \$NPV value or as a benefit/cost ratio.

This method determines system wide benefits instead of only focusing on device efficiency. While this is an improved methodology it does not look at long term cost associated with maintaining the efficiency or performance level of the asset over the life cycle of the asset.

Attached as Exhibit A is: STRAW PROPOSAL OF ICE ENERGY, INC. ON LOAD IMPACT ESTIMATION FROM DEMAND RESPONSE AND COST-EFFECTIVENESS METHODS FOR DEMAND RESPONSE prepared for the state of California by Ice Energy. This is a comprehensive view of how the Ice Bear improves all aspects of the supply chain.

3) A best practice methodology would be to incorporate the TRC cost analysis while adding over all cost of maintenance and operations over a 20 year life cycle, or the published life cycle of an asset, so that the "all inclusive investments" could be compared and the lowest cost energy solution would be provided to the end users. After all, the life cycle cost is the real cost to the utility and the rate payer.

4) Decoupling cost is a factor in this methodology and in addition to decoupling there should be a process to reward best actors and a penalty to fine poor actors.

Some examples are:

If a utility invests \$3800/KW in a solar farm vs. building a gas peaker at \$1400/KW the differential in cost should be recovered by the utility as well as a premium of 25 % or more to reward them for changing habits for the benefit of society as well as taking measures to change from carbon based fuels to clean energy.

In respect to distributed energy storage, the total impact of the assets on the systems should be considered.

In the case of evaluation of different types of energy storage, the longer the initial life cycle of the product, the cleaner the storage medium, the greater the reward should be to the utility.

For example if comparing two types of energy storage:

1= Lithium battery

Vs

2 = Ice Bear Thermal storage using water as its medium.

A higher reward should be attributed to the water based medium#2, than the chemical based medium #1

Also if the life cycle of the lithium battery is 5 years and the life cycle of the water based storage is 15 years a higher reward should be provided to the utility from the PUC than with the Lithium based battery.

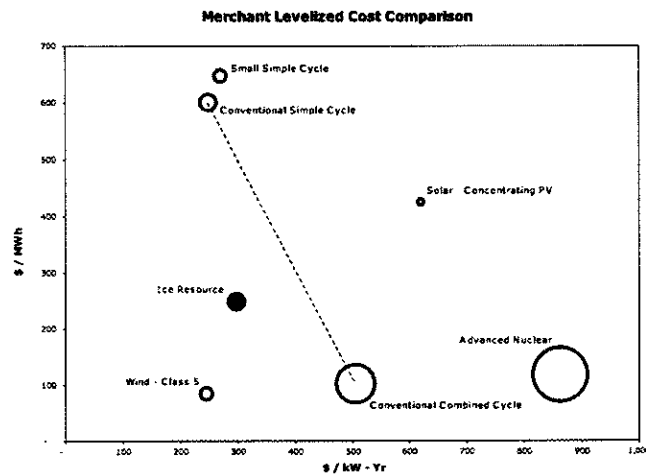
Then finally, the cost of renewing the technology, as well as the waste disposal that would be created by some of these technologies should be considered.

The California Energy Commission has done a comprehensive study on generation. I am providing this document and it's summary below and the complete document is provided in Exhibit B. There are some surprising results from this work that should be beneficial to the Virginia legislature and the utilities that serve the state.

Proprietary & Confidential

Levelized Cost

➤ The Ice Resource is cost-effective



Source: California Energy Commission, "Comparative Costs of California Central Station Electricity Generation Technologies," December 2007, CEC-200-2007-011-SF; Ice Energy for Ice Resource.



As a reference a dotted line connecting the two most popular assets used by utilities. The dotted line establishes a base cost and anything falling to the left of the line is more cost effective. Assets falling to the right of the line cost more. This graph shows where the Ice Power plant (100 MW or more of Ice Bears) would fall in the comparison.

The largest contributor to peak load is air conditioning of commercial and residential buildings. The DOE funded a project several years ago to develop a energy storage device that would use water as its storage medium and standard commercial air conditioning parts as the mechanism to make ice. This was developed to shift the energy used to cool buildings to off peak hours. The result of the DOE's grants to Powell Engineering in the early 1970 and what is now, Ice Energy's Ice Bear30 Smart Grid Thermal storage system.

In the diagram below the picture on the left shows the typical energy used in commercial buildings today and the same profile is true for residential.

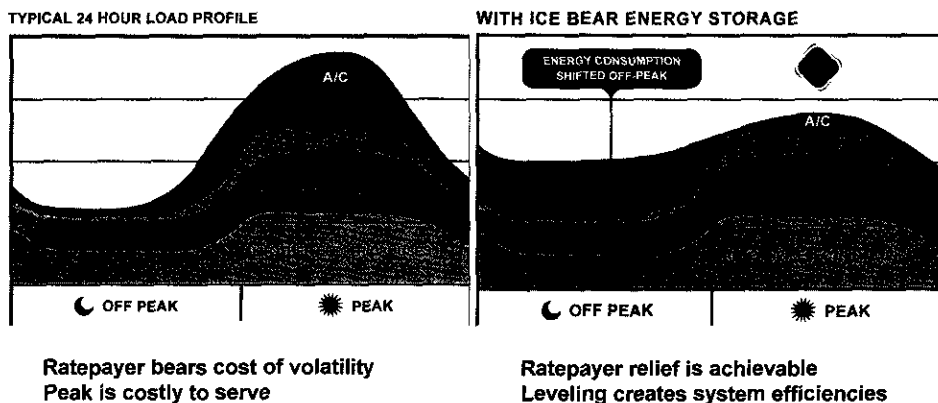
The picture on the right shows the impact of shifting the energy used to cool the building to off peak generation. This simple technology will improve the load factor on the grid, reduce the utilities cost to generate electricity and avoid large capital cost to upgrade the transmission and distribution of electricity by reducing peak load on substations and feeders.

It also protects the utilities revenues as they are still generating and selling electricity but at optimal times improving overall operation of existing infrastructure.

Thermal Energy Storage for Buildings

Eliminates thermally driven "peaky" load shapes by:

– shaving the peak and filling the trough



Ice Energy has developed a large scale deployment process where utilities can purchase 25MW, 50MW or 100MW scale programs that are distributed across multiple feeders in the utilities service area and the units are fully dispatchable just like generators, to meet the changing needs of the utility on a minute by minute basis.

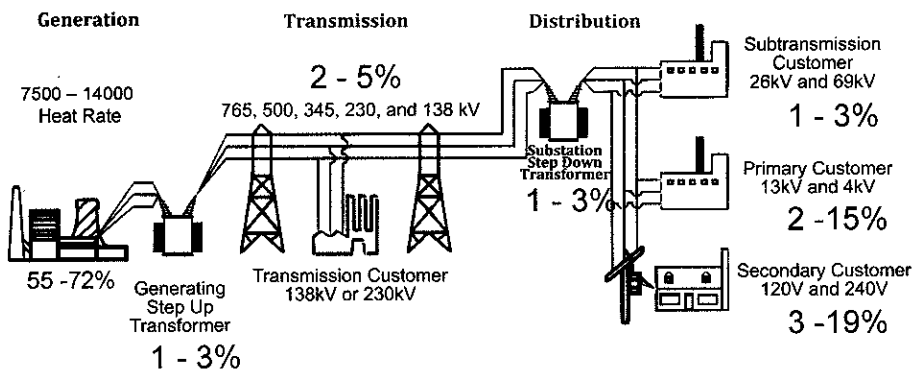
In regard to energy efficiency for the end user, the Ice Bear is worst case energy neutral and in most cases reduces the amount of energy required to cool buildings. This is dependent on the climate zone the units are deployed . Attached is a comprehensive report of the CEC that identifies efficiency of the Ice Bear in 16 different climate zones.

The fact is the hotter the temperature the better the unit performs. The more humid the environment the better the unit performs. This is the inverse of air conditioning and the reason why the Ice Bear is the perfect tool for the utility to reshape load with out curtailment while improving comfort to the end user.

I am also providing diagrams that show typical losses incurred by the utility on a daily basis and it emphasizes the difference in efficiency from day to night across the system. The figures are based on data from utilities and the range shows the average. There are some that fall outside these and mostly on the higher side.

The Impact of Storage on Energy System Efficiency

Typical Electrical System Average Losses

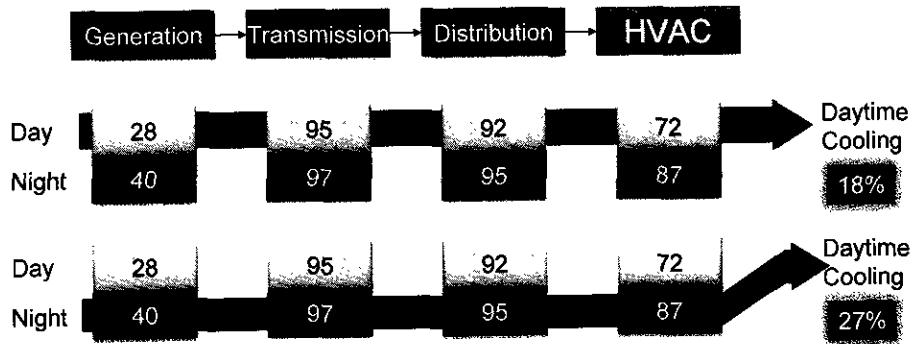


A 100 MW class deployment of the Ice Bear provides approximately 13,000 units installed on 3500 commercial buildings, cell towers and data centers across the utilities services area. These units are each equipped with a smart grid CoolData™ controller that provides 2 way communications to the utility making it fully dispatchable and smart grid compliant. Ice Energy has been rated the number one smart grid control device in the US to date by Smart Grid News as well as winning a number of awards from various organizations for it's smart grid compliance.

By installing a few hundred Ice Bear Smart Grid Thermal storage units across a feeder and substation in a constrained area the load is reshaped by several megawatts and the utility does not have to install larger transformers, and increase wire size to provide additional capacity. This also results in reduction of fuels required to deliver the energy.

Lastly, the graph below shows the improved efficiency of power generation and delivery from a day to night time perspective. It is clear that total systems operations are more efficient at night. By using the Ice Bears for permanent load shifting, energy, and cost are improved allowing the utility to drive down cost to the end user.

Energy End-to-End Electrical System Energy Efficiency
 ...with Ice Bear or Thermal Energy Storage



- Ice Bear storage uses fuel 50% more efficiently ($18\% * 1.5 = 27\%$)
- Ice storage avoids interconnection issues, safety concerns, and conversion losses.
- Nothing is lower cost or safer for the environment than water as a storage medium.

Environmental benefits.

In addition to the benefits of reducing energy and cost of energy system wide, the Ice Bear reduces GHG and NOx significantly. I have attached reports from independent labs and utilities that provide significant data regarding emissions reduction when incorporating the Ice Bear Thermal storage system in the utility network.

See Exhibit D

Please contact :
 David Prezioso
 Vice President, Strategic Business Development
 Ice Energy
 770-565-5738
dprez@ice-energy.com

For questions or further information.

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

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DOCUMENT CONTROL

**STAFF REPORT
(PRE-FILED STAFF TESTIMONY)**

**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 ELECTRIC UTILITY IDENTIFIED BY
CHAPTERS 752 AND 855 OF THE 2009 ACTS
OF THE VIRGINIA GENERAL ASSEMBLY**

CASE NO. PUE-2009-00023

September 9, 2009

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DIVISION OF ECONOMICS AND FINANCE
Howard M. Spinner

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STAFF CONSULTANT WITH BATES WHITE, LLC
J. Nicolas Puga

PART B

PART A

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

**PRE-FILED TESTIMONY
OF
HOWARD M. SPINNER**

CASE NO. PUE-2009-00023

September 9, 2009

**PREFILED TESTIMONY
OF
HOWARD M. SPINNER**

PUE-2009-00023

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE COMMISSION.

A1. My name is Howard M. Spinner. I am Director of the Commission's Division of Economics and Finance.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. My testimony will address the questions raised in a section numbered 10.1-1307.02 of the Code of Virginia enacted by the 2009 Virginia General Assembly effective July 1, 2009. I will also address, either explicitly or implicitly, the questions posed in the State Corporation Commission's ("SCC" or "Commission") Order of April 28, 2009, that initiated this proceeding.¹ My testimony will specifically:

- Provide information regarding the range of consumption and peak load reductions that are potentially achievable by each generating electric utility in response to separate pricing and DSM/EE/DR² programs;

¹ Staff Witness Nicholas Puga of the Bates White consulting firm will also address the Commission's questions in separate pre-filed testimony.

² "DSM," "EE," and "DR" in this testimony means Demand Side Management, Energy Efficiency and Demand Response, respectively. DSM and EE programs are usually considered to be synonyms and generally refer to utility or third party administered initiatives that seek to provide end-use equipment or incentives to purchase end-use equipment to customers such that the result is the same level of end-use

- Provide information regarding the range of costs that consumers would pay to achieve those reductions;
- Provide information regarding the range of financial benefits or savings that could be realized if the targets were met over a 15-year period;
- Discuss issues related to determining a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-side management programs, including an examination of the class cost responsibility methods used in other jurisdictions; and,
- Provide information regarding other jurisdictions that permit certain non-residential customers or classes of customers either to be exempt from paying for the utility demand-side management programs or to opt out of participating in or paying for the utility demand-side management programs.

Q3. HOW IS YOUR TESTIMONY ORGANIZED?

A3. Section I contains initial remarks that discuss, among other issues, the appropriate test for energy efficiency cost/benefit analysis and closely related sub-topics. Section II presents evidence regarding the importance of electric utility prices in determining customer consumption decisions. Here, I present a range of energy reductions that can be expected to result from assumed price changes using a standard industry estimate for the

“energy service” while less electric energy is consumed. DR programs refer to load or peak management programs that seek to increase the electric utility’s load factor by reducing peak load relative to average load.

long-run price elasticity of demand for electric service. In laymen's terms, this section shows how, if the price of electricity rises, customers will use less of it.

In Section III, I present a range of specific energy and capacity savings expected to result from utility initiatives designed to impact customer use through centrally administered "efficiency" programs. Unlike the analysis set forth in Section II, Section III presents the expected results that can be directly attributed to utility sponsored Demand-Side Management/Energy Efficiency (DSM/EE) and Demand Response (DR) programs. The reported information covers the types of DSM/EE/DR programs and other measures required to meet a range of consumption reduction goals, the up-front costs of those programs and measures and the rate impact of program and measure deployment. The content in Section III is generally taken from the testimony and discovery responses of Dominion Virginia Power ("DVP"), Appalachian Power Company ("APCo"), and Old Dominion Power Company ("ODP") as well as respondent testimony in this matter.

Staff Witness Nicholas Puga of the consulting firm Bates White provides a separate engineering analysis of the Section III data. Mr. Puga's analysis is designed to advise the Commission of the likelihood that the expected portfolio of programs will be able to achieve the expected range of electricity savings. Mr. Puga also reviewed the July 31, 2009 submittals

of non-utility respondents who provide testimony related to estimates of electricity savings.

Section IV discusses issues associated with potential ratemaking methodologies that may be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-side management programs, including an examination of the class cost responsibility methods used in other jurisdictions. This section will also examine and report on other jurisdictions that permit certain nonresidential customers or classes of customers to either be exempt from paying for utility demand-side management programs or to opt out of participating in or paying for the utility demand-side management programs.

I. INTRODUCTORY COMMENTS

Q4. HOW DOES THE CURRENT ECONOMIC CLIMATE IMPACT THE ISSUES BEFORE THE COMMISSION IN THIS PROCEEDING?

A4. The current state of the economy is a crucial consideration for public policy makers' determination of a sound approach to energy efficiency issues. It is no secret that the U.S. economy, and possibly the Virginia economy, is suffering through the worst macro-economic downturn since the 1930's.

These adverse economic conditions have impacted more than just employment and economic output; energy prices have fallen precipitously over the past 10 or so months.³ I provide the following table as an example:

TABLE 1

Year	Month	Monthly	Monthly	Monthly
		Average Daily Load (MWH)/24 hours	Real Time LMP PJM Classic + APS	Natural Gas Price
		PJM Classic + APS		Transco Zone 6
2008	1	41,362	\$ 76.61	\$ 12.39
2008	2	41,150	\$ 74.78	\$ 10.68
2008	3	37,347	\$ 75.41	\$ 10.29
2008	4	34,358	\$ 77.20	\$ 10.94
2008	5	33,843	\$ 69.47	\$ 11.98
2008	6	42,768	\$ 107.05	\$ 13.62
2008	7	45,623	\$ 102.22	\$ 12.42
2008	8	41,009	\$ 78.72	\$ 8.82
2008	9	38,294	\$ 76.20	\$ 8.08
2008	10	34,461	\$ 54.58	\$ 7.25
2008	11	36,611	\$ 57.68	\$ 7.47
2008	12	40,159	\$ 53.96	\$ 7.76
2009	1	43,390	\$ 66.84	\$ 9.60
2009	2	40,192	\$ 49.10	\$ 6.15
2009	3	36,627	\$ 42.96	\$ 5.00
2009	4	34,010	\$ 36.23	\$ 4.10
2009	5	33,404	\$ 34.65	\$ 4.12
2009	6	37,407	\$ 34.02	\$ 4.11
2009	7	40,241	\$ 33.84	\$ 3.70
2009	8	43,631	\$ 38.28	\$ 3.78

³ News outlets reported on August 27, 2009 that natural gas prices slumped to their lowest level in seven years after the government reported that salt caverns, aquifers and other underground areas where it is stored are filling up. Levels of natural gas have been building because power-intense industries like manufacturing have cut back severely on production. Natural gas tumbled 4.5 cents to \$2.865 per 1,000 cubic feet. The price dropped as low as \$2.692 per 1,000 cubic feet earlier in the day, a price not seen since Aug. 7, 2002.

This table demonstrates that current, short-run (spot) energy prices, as depicted by PJM LMP,⁴ are one-half to one-third of the levels experienced last summer. Natural gas prices have fallen by about two-thirds since the summer of 2008.

The task before the Commission in this proceeding is to develop a report to the Governor and General Assembly pertaining to the manner in which energy conservation programs should be implemented in Virginia. The fact that energy prices have fallen so precipitously over the past year is important to the discussion. Energy efficiency programs use real and expensive resources (capital, labor, materials, etc.) to generate streams of electricity savings that are expected to persist into the future. As will be discussed in great detail below and in attachments to this testimony, cost-effective efficiency programs are those where the cost of achieving the efficiency is less than the cost of the forgone electricity supply. When the cost of electricity changes, this overarching test of cost-effectiveness is impacted. When the cost of electricity changes as much as it has in recent history, the potential for energy efficiency that is truly cost-effective will also change.

The above paragraph suggests that, because the market price and the underlying cost of the fuel (natural gas, in the above table) needed to

⁴ "PJM LMP" is the locational marginal price for electric energy for a particular location. Here I include the price for original, pre-expansion PJM but I do include Alleghany Power (APS) in the region.

produce electricity has fallen by a substantial amount, the Commonwealth should be less willing to spend money to save electricity --- all else held constant. There are, however, other factors beyond current price that need be considered. Policy makers need to form expectations about the future costs of both efficiency and electric supply as well as non-price considerations (“externalities”) that stem from alternative ways of meeting Virginia’s energy needs. For example, while burning coal to make electricity produces priced and presumably non-priced environmental costs, it also produces jobs for coal miners and the associated commerce that goes with employment.⁵ This testimony strives to point out these tradeoffs and offer key recommendations, and is directed towards providing policy makers with as much relevant information as possible.

Q5. WHAT EXPERIENCE HAVE YOU HAD RELATED TO ELECTRICITY PRICING, ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT, DEMAND RESPONSE, RATE DESIGN AND SPECIAL CONTRACT DEVELOPMENT THAT IS HELPFUL TO THE COMMISSION’S CONSIDERATION OF THIS MATTER?

A5. Prior to joining the Commission’s Staff in 1998, I spent eleven years at investor-owned electric utility Central Vermont Public Service (“CVPS” or

⁵ For example a July 30, 2009, article in the *Wall Street Journal* titled “Once-Hot Coal Piles Up as Demand Cools” states in the concluding paragraph: “Coal companies, which began cutting production and laying off workers in the 2008 fourth quarter, are expected to announce more of both.” The article focused on Central Appalachia mines located in parts of Tennessee, Kentucky, West Virginia and Virginia.

“Central Vermont”) in positions of increasing responsibility. Beginning in the early 1970’s and outlined in greater detail in Section II below, CVPS instituted an extensive array of programs and other measures, such as rates, tariffs, and contracts to induce customers to use electricity more efficiently. Beginning in 1988, the Vermont Public Service Board (“VPSB”), which is the state utility regulatory agency there, initiated a comprehensive proceeding to explore the provision of demand-side management and energy efficiency programs that went beyond rate design as a means of altering the quantity or pattern of customer electrical consumption. That proceeding (docketed as VPSB Docket No. 5270) and its progeny lasted for several years. I was involved in several aspects of Central Vermont’s intense work in those cases including filing extensive testimony in VPSB Docket Nos. 5270-CV-1 and 5270-CV-3 on matters related to the efficacy of using prices as a means of promoting the efficient use of electric power. As an example of the length of time consumed by these matters in Vermont, I note that this testimony was filed in 1993.

These points bear mentioning because Vermont has, for better or worse, been recognized as a leader in the provision of DSM/EE. Interestingly, before Vermont adopted DSM/EE programs, the Green Mountain state was a leader in the design and implementation of innovative electrical rates whose underlying purpose was to induce customers to take

actions that saved electrical energy and capacity *on their own*. Those pricing programs proved to be highly effective.

As Vermont's largest electric utility, Central Vermont played an integral part in the evolution of public policy as it relates to the provision of both pricing (i.e. rate design) and DSM/EE programs. During my time at Central Vermont, I was deeply involved in the internal debates that lead to the development of Central Vermont's positions on DSM, EE and related issues of appropriate rate design as an alternative means of maximizing the societal net benefits of producing, transporting and consuming electric power. I believe that the basic arguments, controversies and policy considerations remain unchanged to this day. As such, the experiences I gained at CVPS as the State of Vermont worked through many of these same issues provide a strong basis for my participation in this matter.⁶

Q6. PLEASE PROCEED WITH YOUR INITIAL REMARKS.

A6. The tasks assigned by the General Assembly to the Commission that gives rise to this proceeding require complex analysis that can be very controversial. Similar proceedings in other jurisdictions have taken far

⁶ DSM and EE services in Vermont are now provided by an entity called Efficiency Vermont. Created in 2000 by the Vermont legislature and the Vermont Public Service Board, this entity purports to help all Vermonters save energy, reduce energy costs and protect Vermont's environment. After this entity began operation, Vermont electric utilities (except the municipally owned Burlington Electric Department) were able to stop providing energy efficiency services. This enabled almost all Vermonters to receive the same services.

longer to complete than the time allotted the Commission to complete this matter. It should also be noted that other related proceedings are currently underway; Virginia's investor owned electric utilities filed Integrated Resource Plans ("IRP") on or about September 1, 2009, and Dominion Virginia Power filed for a rate adjustment clause to recover certain DSM/EE/DR and related costs on July 27, 2009. These dockets are closely intertwined with the instant matter and proceed simultaneously with this case.

With a November 15, 2009, due date for a Commission report to the Governor and General Assembly, the Commission commenced this proceeding on April 30, 2009. Even though the April commencement was approximately 60 days before the effective date of the legislation that gives rise to this proceeding, the time available for analysis of these complex issues is quite short. This abbreviated time frame requires the use of a great many assumptions throughout this testimony. It is likely that respondent testimony is based on assumptions as well. Further, it is undeniable that one can use alternative assumptions to arrive at alternative results.

Finally, I note that the legislation initiating this proceeding stated:

The Commission shall determine which test should be given greatest weight when preparing a cost-benefit analysis of a demand-side management program, taking into consideration the public interest and the potential impact on economic development in the Commonwealth.

Staff's overarching objective in this matter, therefore, is to promote both the public interest and economic development in the Commonwealth via its participation in this proceeding.

Q7. PLEASE PROVIDE AN EXAMPLE OF HOW DVP'S DSM COST RECOVERY REQUEST DOCKET AND THIS MATTER INTERACT.

A7. A relevant and important example of the interaction of these matters is related to DVP's Voltage Conservation Program ("DVP VCP"). Although DVP requests approval of program cost recovery for DVP VCP in PUE-2009-00081, DVP holds that this program will provide the vast majority of projected DSM/EE MWH savings in the instant matter. Since DVP is Virginia's largest utility and DVP VCP is the largest DSM/EE program in terms of projected savings as well as projected expenses, Staff Witness Puga devotes a substantial portion of his testimony to the DVP VCP program.

Although it is not Staff's purpose to litigate here issues relating to DVP VCP perhaps more appropriately handled in PUE-2009-00081, DVP's reliance on DVP VCP to deliver the vast bulk of DSM/EE MWH savings presents important issues here relating to the cost effectiveness of meeting any potential MWH reduction goal via a DSM/EE portfolio that includes DVP VCP. As such, Staff has devoted considerable time and effort evaluating the DVP VCP program.

Q8. WHAT HAS STAFF LEARNED ABOUT DVP VCP?

A8. According to the company, DVP VCP is a cost effective energy efficiency measure that requires the change out of much of the company's metering plant. This change out will allow for more precise control of voltage over much of the company's electricity delivery network. DVP holds that this increase in voltage control will cost effectively save energy. However, the metering equipment to be replaced has many remaining years of useful life and is valued at hundreds of millions of dollars on the company's books. DVP cost justifies its VCP program by "pricing-out" a stream of claimed energy savings at a forecasted energy value through time, calculating a present value of these savings in dollar terms, and comparing that present value with the cost of the program. DVP's claimed energy savings are derived from a pilot deployment of this technology on two distribution feeders in suburban Richmond.

It is likely that Staff will dispute many aspects of the company's cost justification of this project. Preliminary econometric, statistical and comparative work that I have done indicates that DVP has over-estimated the present value dollar benefits of DVP VCP by over-estimating the MWH saved, over-estimating the dollar value of a saved MWH through time and using too low a discount rate to calculate the present value of the stream of alleged savings. In his testimony in this matter, Staff Witness Puga engages in a detailed engineering discussion from an end-use perspective

again doubting the ability of DVP VCP to save the claimed amount of energy.

Finally, note that by this discussion I seek only to lay information on the table and wish to imply nothing as to a potential Staff recommendation to the Commission for a matter to be handled in a later docket. My non-recommendation is based on more than timing. DVP VCP can be thought of as a kind of "cash-for-clunkers" (CARS) program applied to electric meters and ancillary control equipment. DVP's justification for VCP program expenditures points to more than just MWH savings resulting from more refined distribution feeder voltage control. Just as the federal CARS program had environmental as well as economic justifications, DVP VCP is claimed to have other benefits. Extending the analogy a bit further, I note that DVP has told the Staff that they will seek federal economic stimulus money to help fund the program. The results of that task, as well as the accounting treatment of any federal dollars received, may determine the efficacy of DVP VCP from the perspective of the company's ratepayers or other perspectives that policy makers may wish to consider.

Q9. PLEASE EXPAND UPON THE IMPORTANT ISSUE OF WHICH TESTS FOR DSM/EE/DR "COST-EFFECTIVENESS" SHOULD BE EMPLOYED BY THE COMMONWEALTH.

A9. This question has been debated for many years. In the Order opening this proceeding the Commission asked generating electric utilities and respondents the following question:

What industry-recognized tests should be used in determining cost-effective consumption and peak load reductions and what relative weighting should be afforded to any test recommended for use by the respondent generating electric utility?

In their June 30, 2009, direct testimonies in this matter witnesses, for APCo and ODP endorse the Total Resource Cost Test ("TRC Test") as the primary test for program cost effectiveness. DVP does not endorse any particular test. Other respondents generally endorse either the TRC Test (or some variant thereof) or the Ratepayer Impact Measure Test ("RIM Test"), with DSM/EE advocates recommending the former and large industrial customers or their representatives recommending the latter.

Q10. WHAT IS THE TRC TEST?

A10. Both APCo and ODP offer a definition of the TRC Test. While the definitions differ, the basic idea is the same. The TRC Test seeks to determine which costs less; a unit of electrical energy supplied from the utility grid or the alternative conservation of that unit of electric supply. Staff would agree that this is the most important test for determining cost-effectiveness of EE/DSM programs --- if the TRC Test could be accurately performed. Note that the TRC Test is not concerned with the impact of the DSM/EE program on utility rates; the TRC Test says nothing about rates.

Rate impacts are evaluated via the use of the Rate Impact Test (“RIM Test”). The RIM Test evaluates the effect on rates of deploying an EE/DSM program in lieu of the traditional grid supply alternative.

Although Staff agrees that the TRC Test should be of primary importance if indeed it could be accurately performed, practical limitations in our ability to accurately perform the TRC Test leads Staff to continue its advocacy of the RIM Test. The practical limitation I speak of is that accurate TRC testing requires a level of knowledge not possessed by any efficiency provider, utility or governmental agency. APCo witness Thomas may have this in mind when he states that “The utility is not omnipotent.”⁷

The difficulty of performing the TRC Test is evident in its name. It is virtually impossible for any tester to know about and quantify the total resources required to provide any good or service. That is why our economy relies on a system of prices, not underlying costs, to allocate scarce goods and services. Prices can be posted and observed; calculating the costs of the total resources required to meet an economic want or need is much harder to do. Some argue that it simply can’t be accurately done. Since total resources can’t be (easily) quantified in a TRC Test, it can be shown algebraically⁸ that EE/DSM measures that pass a TRC Test must pass a TRC Test. Measures that do not pass a TRC Test may or may not

⁷ Pre-filed testimony of Barry L. Thomas, June 30, 2009, at page 7.

⁸ See Exhibit HMS-2 attached to this testimony.

pass a TRC Test that includes hard or costly to identify/quantify resource costs. An intuitive example follows.

Suppose all stakeholders agreed that it would be cost-effective if the five most frequently used incandescent light bulbs in each residential customer residence were switched to appropriately sized compact fluorescent lights ("CFL") compatible with the fixture into which each would be placed. In other words, a TRC Test *could* be constructed such that this CFL measure would pass. Note that this seemingly simple proposition is packed with potentially controversial assumptions, including but not limited to, (1) the idea that CFLs are more likely to be cost-effective the greater the use of that fixture,⁹ (2) the idea that every household has at least five light fixtures that operate enough hours per year to produce sufficient energy savings, (3) the idea that, but for the EE/DSM program, the customer would not purchase CFLs (five or some other number) at full retail price at the local store,¹⁰ (4) and that changing these five light fixtures will have no impact on the number of lumens demanded by the consumer. Again, setting all of these valid controversies aside, the question is how do we get the five CFLs into the household in the right

⁹ If the CFL is not used at all, it can't be cost-effective. Providing costly CFLs to customers that don't use them cannot pass any test of cost-effectiveness. As the amount of displaced usage increases, the CFL becomes more cost-effective since its energy requirement per lumen of output is lower than that of a standard incandescent light bulb.

¹⁰ The validity of this notion has changed over the past twenty years. Two decades ago CFLs were truly novel. These days CFLs work better, cost less and are widely available.

size, type and style to assure their full utilization and make sure that all the cost and benefits of doing so are included in a TRC Test?

It may be that one way to accomplish this feat is to undertake various types of surveys to ensure correct CFL placement. These surveys can have varying costs ranging from having the customers order the five CFLs from a descriptive brochure to having a program representative visit each residential household. The point is that what started out as a relatively simple notion, i.e., changing five light bulbs, can get quite complex --- and expensive --- in actual execution.

Q11. WHERE DOES THIS LEAVE US REGARDING THE TRC AND RIM TESTS?

A11. This discussion began with the assertion that it would be cost-effective to exchange five CFLs for incandescent bulbs, per household, assuming that we could replace the five most intensively used bulbs in each household. A TRC Test could be performed that assumes that any program delivery method will precisely target these five bulbs. Here, the program might pass a TRC Test. Alternatively, the program design may undertake the more costly task of ensuring that the right mix of CFLs is delivered to each household. If these extra costs are considered as "resources" (as they should be), then the program might have a harder time passing a TRC Test.

A third outcome might be that the extra costs required to ensure correct CFL fitment --- thereby ensuring that the bulbs will actually provide

lumens in place of the less efficient incandescent bulbs --- are considered as "transfer costs" and are not included in the TRC analysis. This last scenario focuses only on the lumens produced by the alternative method (CFLs versus incandescent) and ignores some of the actual costs of program implementation.

While the TRC Test is conceptually the correct test to apply, this discussion demonstrates that TRC testing is not straightforward and is very hard to do right. RIM testing, on the other hand, is relatively easy and yields acceptably accurate results. This is especially true in the short term.

Q12. WHY IS THIS POINT REGARDING THE RELATIVE DIFFICULTY OF CONDUCTING TESTS FOR COST EFFECTIVENESS IMPORTANT?

A12. In Section III below, I report and summarize the answers of the respondent utilities regarding the cost of achieving various levels of electrical savings due to the implementation of EE/DSM. While it may be argued that, in the long-run, programs that pass a TRC Test will lower rates, the potential for errors and omissions (not all costs being counted) mean that the more expensive the program, the more likely the program is to raise rates to consumers. Moreover, if today's electric rates exceed the marginal cost of providing the saved kWh, there is a lost contribution to the utility's fixed cost of providing service. Recovery of that lost contribution puts upward pressure on rates.

The Commission asked about the range of costs that consumers would pay to achieve reductions due to the implementation of EE/DSM/DR programs. These costs may be recovered in rates, required customer co-payments to purchase energy efficiency devices, or appear as customers install and live with the energy efficiency devices. Again, the greater the cost of the program, the more likely it will be that customers pay more for energy services, holding all else constant.

Q13. IF AN EE/DSM/DR MEASURE PASSES A TRC TEST DOESN'T IT MEAN THAT SAVING ELECTRICITY COSTS LESS THAN PRODUCING IT, SO CHOOSING EFFICIENCY MUST LOWER RATES?

A13. I have several parts to my answer. The first is that, as explained above, it is very difficult --- if not impossible --- to perform the TRC Test accurately. Since customers incur real but impossible to completely measure costs when they deploy and live with DSM/EE/DR, the insurmountable real world problem is that the total resource cost of efficiency can't be correctly determined.¹¹

Second, if a TRC Test could be accurately performed and we were sure that EE/DSM/DR costs less than traditional supply, efficiency should be chosen to meet the need for energy services. If efficiency is chosen and

¹¹ This issue is extensively discussed in Exhibit HMS-2 attached to this testimony.

the rate forgone by the utility exceeds the utility's cost of providing the forgone electric service, rates must rise if the utility is to be made whole. Third, while efficiency advocates often claim that such a rate increase is only a short-run phenomena and promise that rates will be lower than what would otherwise prevail out in the future, the near-term rate increase happens with certainty. Since the potential long-run rate lowering benefits of efficiency are more speculative, it will be hard for some customers to favor certain near-term rate increases for less certain longer-term rate reductions.

A fourth factor is the consideration of externalities. TRC testing ought to include all resource costs, including priced and un-priced external goods and bads. The obvious problem is that it is impossible to accurately include un-priced externalities in any quantitative analysis. Assumptions made to include such un-priced externalities are subjective. Leaving out un-priced externalities means the TRC Test is not including total resource costs. This is another example of the difficulty of performing accurate TRC testing. It is easier to define a test and assume it can be done accurately than it is to actually perform the test accurately.

To summarize my answer, I hold that TRC testing would be correct if such testing could be accurately performed. A measure that passed a TRC Test could, however, still cause rates to increase. Even if such an increase was restricted to the near-term and indeed led to lower rates in the

long-run, it is not a straightforward exercise to determine which rate path is preferred by utility consumers. Finally, consideration of quantifiable or unquantifiable environmental or other externalities, whether positive or negative, associated with the production and consumption of electric power versus the production and consumption of efficiency greatly complicates this discussion to the point where alternative assumptions could be employed to justify almost any policy path.

Q14. HOW DO "FREE-RIDER" ISSUES AFFECT COST/BENEFIT ANALYSIS OF EE/DSM PROGRAMS?

A14. Consideration of free-rider issues in cost/benefit analysis of DSM/EE programs is warranted but serves to further complicate matters. Continuing on with the CFL analogy, a free-rider is someone who takes an available monetary incentive yet would have purchased the CFL without the incentive. The example below demonstrates the relationship between free-riders and the cost of the efficiency "resource."

TABLE 2

Total CFL Sales in w/ Rebate	250,000	250,000	250,000	250,000
Baseline CFL Sales ¹	100,000	150,000	175,000	200,000
Incremental CFL Sales	150,000	100,000	75,000	50,000
Annual kWh Savings/CFL	75	75	75	75
Total Annual Energy Savings (kWh)	11,250,000	7,500,000	5,625,000	3,750,000
Avoided Power cost (\$/kWh)	\$ 0.080	\$ 0.080	\$ 0.080	\$ 0.080
Total Annual Energy Savings (\$)	\$ 900,000	\$ 600,000	\$ 450,000	\$ 300,000
Cost of Rebate	\$ 1.25	\$ 1.25	\$ 1.25	\$ 1.25
Rebates provided	250,000	250,000	250,000	250,000
Annual Rebate Cost	\$ 312,500	\$ 312,500	\$ 312,500	\$ 312,500
Program Overhead	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000
Total Program Cost	\$ 412,500	\$ 412,500	\$ 412,500	\$ 412,500
Program Cost per kWh Saved	\$ 0.037	\$ 0.055	\$ 0.073	\$ 0.110

¹ Baseline Sales are the assumed sales that would occur in the absence of the rebate program. These are the "free-riders."

This simple example demonstrates that as the number of free-riders increases, the energy savings attributable to the program falls and the cost per kWh saved increases.¹² In the extreme case where everybody is a free-rider, the same level of CFL penetration would result with or without the program. As such, all program expenditures are wasted.

The above example is non-trivial as it relates to CFL deployment. If current efforts to ban incandescent lighting come to fruition, increased CFL penetration would become guaranteed without any centrally administered efficiency program. If an EE/DSM program focused on CFL deployment,

¹² This example is offered to demonstrate the direction of a trend. Actual energy impacts due to bulb switching could persist for more than one year.

free-ridership would approach 100% and would be easy to forecast. In general, however, free-ridership as it applies to energy efficiency programs is very hard to predict. This is an example of another difficulty that must be overcome to correctly administer the TRC Test.

Q15. WHY IS THE PRE-FILED TESTIMONY OF WILLIAM STEINHURST (ON BEHALF OF THE SOUTHERN ENVIRONMENTAL LAW CENTER, ET AL) ESPECIALLY ILLUSTRATIVE OF THESE ISSUES?

A15. Witness Steinhurst advocates the use of the TRC Test --- with certain adjustments. Although his adjustments would increase DSM/EE provision relative to grid supply alternatives, the fact that he proposes rather arbitrary adjustments to the TRC Test at all illuminates my point about TRC testing difficulties. By proposing his selected adjustments, Dr. Steinhurst must believe that the TRC Test does not include all the costs and benefits needed to solve the problem. While he believes that the TRC Test --- without his proposed adjustments --- misses some costs of grid supply and some of the benefits of DSM/EE, I believe that the TRC Test misses enough of the costs and benefits of both grid supply and DSM/EE that the TRC Test does not produce reliable results.

I should note that Dr. Steinhurst and I go back a long way on these issues. Twenty years ago, electricity policymakers in Vermont chose to go down the path advocated then (and here) by Dr. Steinhurst. This current

proceeding indicates that Virginia did not choose a similar path back then. It would be analytically convenient if these different policy paths were the only difference in electricity policy over the last twenty years between these two states. If that were true, we could observe comparative industry results to determine the superior policy path. Unfortunately, there were a number of other important changes in both Virginia and Vermont that would make such analysis just as difficult, subjective and controversial as the policy debate that is already before this Commission in this docket.

To sum up, I advocate actions that seek to price electricity as accurately as possible based on the resource cost of producing and delivering the product. If a DSM/EE/DR goal(s) is set for the Commonwealth, I believe that the most cost-effective way to achieve the goal is through the use of price incentives that seek to incent customers to conserve electricity through using less and/or installing their own efficiency devices.

Q16. PLEASE EVALUATE THE CLAIM THAT RATE IMPACTS FROM DSM/EE PROGRAMS ARE LIKELY TO BE SMALL AND, AS SUCH, THE DSM/EE COST/BENEFIT ANALYSIS SHOULD NOT RELY PRIMARILY ON THE RIM TEST?

A16. I first note that efficiency advocates tend to minimize the importance of the RIM Test. However, paying customers commenting in this matter are very concerned about rate impacts. Second, I offer the following data obtained

from Central Vermont's main residential rate (Rate 1) demonstrating the charges collected from customers that fund Efficiency Vermont.

TABLE 3

**CENTRAL VERMONT PUBLIC SERVICE CORPORATION
Analysis of Efficiency VT Charges on Typical Residential Bill**

	Current Base Rates	ESAM	CVPS Electric Charges	Billing Units	Monthly Bill	
Service Charge	0.388	1.15%	\$ 0.3920	30	\$ 11.76	
kWh	0.12294	1.15%	\$ 0.1244	500	\$ 62.18	
PCAM			\$(0.0011)	500	\$ (0.53)	
					\$ 73.41	CVPS Electric Charges
EEC			\$ 0.0067	500	\$ 3.35	Efficiency Vermont Charge
					\$ 76.76	Combined Charges
Bill increase associated with Efficiency Vermont					4.6%	

These data show that a typical residential customer using 500 kWh per month (this is around the average monthly use per residential customer in Vermont) pays \$3.35 per month or 4.6% of his/her total bill to fund the Efficiency Vermont initiative/entity.

Q17. WHAT IS YOUR ANSWER TO THE COMMISSION'S QUESTION REGARDING WHAT INDUSTRY-RECOGNIZED TEST SHOULD BE USED IN DETERMINING THE COST-EFFECTIVENESS OF DSM/EE/DR PROGRAMS?

A17. Due to the difficulties associated with accurate TRC testing, Virginia should rely primarily on the RIM Test to measure the cost-effectiveness of DSM/EE/DR initiatives. In addition, I agree with regulatory economists

that advocate actions that seek to price electricity as accurately as possible based on the resource cost of producing and delivering the product. DSM/EE/DR goal(s) set for the Commonwealth are achieved most cost-effectively through the use of price incentives that seek to incent customers to conserve electricity through using less and/or installing their own efficiency devices. If policy makers determine that other considerations associated with the production and delivery of electric power are important, the TRC Test can be used as the primary driver of cost-effectiveness. This path will likely require rates higher than that of a regime where primary importance is placed on the RIM Test.

II. POTENTIAL IMPACTS FROM PRICING INITIATIVES

Q18. WHAT DO YOU COVER IN THIS SECTION OF YOUR TESTIMONY?

A18. This section seeks to provide an estimate of the range of consumption and peak load reductions potentially achievable by each generating electric utility, the range of costs that consumers would pay to achieve those reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 15-year period *only from the institution of pricing programs designed to reduce electric consumption and peak loads.*

Q19. DO YOU HAVE ANY GENERAL COMMENTS ON ELECTRICITY CONSUMPTION 'GOAL' OR 'TARGET' SETTING AS A MATTER OF PUBLIC POLICY?

A19. Yes. I note again that the last sentence of 10.1-1307.02 B2 § 1. reads:

The Commission shall determine which test should be given greatest weight when preparing a cost-benefit analysis of a demand-side management program, taking into consideration the public interest and the potential impact on economic development in the Commonwealth.

A standard consideration of the public interest and potential impact on economic development as set forth by the statute indicates that any DSM/EE/DR or pricing initiative goal or target setting exercise be subjected to a standard economic analysis. Such an analysis would, I believe, reveal that the course of action that best promotes sound public policy and advances the prospect for economic development in the Commonwealth is one where the first task is to set electricity prices such that usage sensitive rate elements are priced at the appropriate measure of marginal cost. While the preceding statement sounds definitive, it leaves substantial room for policy debate as to exactly what is the "appropriate measure of marginal cost." Is such a measure a short-run or a long-run quantification? How are externalities handled? Should pricing policy treat quantifiable externalities differently than non-quantifiable externalities? While prices should approximate marginal costs, there is much debate as to how to calculate those marginal costs.

A strategy of "efficient pricing" (where prices for usage sensitive rate elements approximate marginal costs), if done correctly, sends an accurate price signal to customers that can be used by customers to design their own DSM/EE or DR programs that consider their own needs and costs.

Given an estimate of the aggregate customer reaction to such a change in price signals (i.e., a long-run price elasticity of demand for use at the margin), an estimate of the change in electric consumption can be determined. It should be noted that such a reduction in demand --- if indeed prices are raised at the margin --- may come at little or no cost to customers in aggregate because rate increases at the margin may be combined with rate decreases for other non-usage sensitive rate elements to allow the utility to collect all the money to which it is entitled. Moreover, if the expected change in demand is not to the policy maker's liking, prices at the margin could be further increased above marginal costs. These higher electric prices would generate an even larger price response and perhaps more net revenues that could be returned to customers in a manner prescribed by law or regulation. One school of thought is that such pricing strategies are the most cost-effective means to get consumption of electric power to either its most economically efficient level or any such other level that policy makers may require.

A policy directive to implement all cost-effective energy conservation and demand response is a worthy directive and may be in conflict with the setting of a pre-determined goal. Simply put, all cost-effective demand-side opportunities should be pursued without regard to achieving a particular goal.¹³ On the other hand, the difficulties associated with testing for efficiency measure cost-effectiveness as outlined in this testimony might lead policy makers to set a goal.

Energy economists generally hold that the policy goal should not be the reduction of energy use --- at any cost --- merely for the sake of reducing energy use and achieving a stated goal. This line of thinking suggests that electricity policy should not have the objective of stimulating or reducing electrical energy use to meet some pre-determined goal. Rather, policy should be directed at encouraging Virginia's electricity consumers to use the correct amount of electrical energy based on the total cost to produce and deliver electric power as compared to the value that customers derive from consuming that power. Such an approach is consistent with legislative findings, policy goals and Commonwealth Energy Policy as it exists in the Code of Virginia.

Q20. WHY ARE ENERGY PRICES IMPORTANT TO CONSUMER CONSUMPTION DECISIONS?

¹³ By this statement I do not mean to trivialize valid debate about how to determine what DSM/EE/DR measures and programs are or are not "cost-effective."

A20. Energy economists have long noted that the prices that consumers pay for electric service greatly impact consumer behavior, including consumer willingness to purchase energy efficiency on their own. If the goal is to cut electric consumption, the most certain way to achieve the goal is to raise electricity prices, especially the price for electricity consumed at the margin.¹⁴

Electricity pricing or "rate design" determines how the relative purchases of electricity versus conservation impact utility shareholders and non-participant ratepayers through rate level changes. The influence of prices on consumer behavior is especially evident over the long run. Pre-occupied with industry restructuring, the nation's electric utility industry has paid little attention to rate design issues over the last decade, especially as they apply to retail mass market customers.

Q21. HOW CAN YOU BE SURE THAT PRICING POLICY IMPACTS CONSUMER CONSUMPTION DECISIONS REGARDING ELECTRIC POWER?

A21. As stated above, I spent eleven years helping to administer a program of efficient prices at CVPS. Those pricing policies, along with load management programs and special contracts, enabled that company to increase its system load factor from around 52% in the early 1970's to

¹⁴ The ability of changes in electricity prices to change consumer demand is the key point of the testimony of Robert Jackson filed in support of Respondent Robert Vanderhye. Simply put, if the goal is to reduce consumer use of electricity the most efficient way to reach the goal is by raising the price of electricity.

about 70% by the mid 1990's. While some may consider this ancient history, I believe the "lessons learned" during this period --- as well as Central Vermont's experience with centrally administered DSM/EE programs beginning around 1989 --- are relevant in this proceeding.

In order to enhance the record in this proceeding, I offer the November 21, 1988, rebuttal testimony of William J. Deehan in Vermont PSB Docket No. 5270. (Exhibit HMS-1) This testimony describes research into the efficacy of Central Vermont's pricing policies during the time period beginning in 1972 and ending in 1988. I am very familiar with this work as well as Central Vermont's costing and pricing policies then in effect.

The major point of Mr. Deehan's testimony is that customers do respond to price signals by undertaking their own conservation measures (which he designates as "customer DSM" in his testimony) in response to higher prices. Customers also respond to lower, off-peak prices by shifting consumption from higher cost peak periods to lower cost off-peak periods. Mr. Deehan estimated the net value of these shifting usage patterns to Central Vermont's customers as electrical resource cost savings less the cost of implementing and communicating resulting price signals to consumers. Mr. Deehan conservatively estimated the savings accruing to CVPS' ratepayers as \$10 M per year, or about 5.4% of CVPS's 1988 retail rate revenues.

Q22. HOW IS MR. DEEHAN'S 1988 VINTAGE TESTIMONY RELEVANT IN THIS PROCEEDING?

A22. Mr. Deehan's research clearly showed two types of strong consumer reaction to changes in electricity prices. First, all of the New England electric utilities in his study experienced slower growth in use per customer as a result of the electricity price increases of the 1970's. Second, Central Vermont customers reacted to time-of-day, marginal cost based price signals by substantially increasing system load factor by a substantial margin by 1987. CVPS system load factor¹⁵ increased from 52% to 64%. These improvements continued into the 1990's with CVPS system load factor reaching the low 70% range. A corollary point of Mr. Deehan's testimony is that other New England utilities that did not institute a marginal cost based pricing regime, did not enjoy similar improvements in electric system utilization.

Under certain assumptions, we can calculate the required price increase necessary to yield a range of consumption reductions for Virginia generating electric utilities (as defined by §10.1-1307.02 of the Code of Virginia).

Q23. WHAT RANGE OF CONSUMPTION REDUCTIONS WILL BE POSITED FOR THIS EXERCISE?

¹⁵ Load factor is the ratio of average system load to peak hour load. As load factor increases the electric system is used more efficiently because less utility plant is idle.

A23. For DVP and APCo, separately, I calculate necessary price increases that yield consumption and peak reductions of 5%, 10%, 15% and 20% in year 2024. I also calculate rate impacts and extra revenues generated by the price increases necessary to achieve the percentage reductions in electricity use.

Q24. PLEASE LIST YOUR KEY ASSUMPTIONS USED TO CALCULATE THE RANGE OF CONSUMPTION AND PEAK REDUCTIONS SPECIFIED HERE.

A24. Although this exercise is relatively simple, the calculations do rely on a few key assumptions.

- I employ a long-run price elasticity of demand of -0.7. This implies that a price increase of 10% will result in a decrease in electrical throughput of 7% - all other factors held constant. I base the use of this long-run elasticity on an informal literature search as well as my background and experience. I readily acknowledge that the elasticity effect for Virginia over the next 15 years may be different.
- I begin with 2008 data for Dominion Virginia Power as follows:
Total Rate Revenues of \$5,200,157,059; total jurisdictional MWH of 63,791,370; and an average rate per kWh of \$0.08152.
- I begin with 2008 data for Appalachian Power Co. – VA as follows:
Total Rate Revenues of \$953,336,016; total jurisdictional MWH of 15,553,396; and an average rate per kWh of \$0.06129.

- I grow loads at 1.5% per year and electricity rates at 3.0% per year between now and 2024.
- I assume that the average rate is the marginal rate per kWh to which the price increases are applied. This is as opposed to affecting the posited price increase by raising non-usage sensitive rate elements such as the customer charge. Raising customer charges would not be expected to yield nearly the same magnitude usage response as would raising usage sensitive, marginal rate elements.

Q25. WHAT ARE THE RESULTS OF THIS EXERCISE?

A25. My results are set forth in the following two tables:

For DVP – Table 4

For the Year 2024

Percent reduction MWh&MW	5.0%	10.0%	15.0%	20.0%
Rate increase required %	7.15%	14.30%	21.45%	28.55%
Increase cents/kwh	0.91	1.82	2.72	3.63
MWh repression	3,991,665	7,983,331	11,974,996	15,938,748
Base Mwh 2024	79,753,554	79,753,554	79,753,554	79,753,554
Delivered MWh - price change	75,761,888	71,770,223	67,778,558	63,814,806
Extra Revenues \$ (000)	\$ 181,022	\$ 289,549	\$ 325,579	\$ 289,621
Total Revenues \$ (000)	\$ 10,310,162	\$ 10,418,689	\$ 10,454,719	\$ 10,418,761
Base Revenue 2024 \$ (000)	\$ 10,129,140	\$ 10,129,140	\$ 10,129,140	\$ 10,129,140

For APCo – Table 5

For the Year 2024

Percent reduction MWh&MW	5.0%	10.0%	15.0%	20.0%
Rate increase required %	7.15%	14.30%	21.45%	28.55%
Increase cents/kwh	0.68	1.37	2.05	2.73
MWh repression	973,238	1,946,477	2,919,715	3,886,147
Base Mwh 2024	19,445,321	19,445,321	19,445,321	19,445,321
Delivered MWh - price change	18,472,082	17,498,844	16,525,606	15,559,173
Extra Revenues \$ (000)	\$ 33,184	\$ 53,078	\$ 59,683	\$ 53,091
Total Revenues \$ (000)	\$ 1,889,975	\$ 1,909,869	\$ 1,916,474	\$ 1,909,882
Base Revenue 2024 \$ (000)	\$ 1,856,791	\$ 1,856,791	\$ 1,856,791	\$ 1,856,791

Q26. WHAT ARE THE IMPLICATIONS OF THESE CALCULATIONS?

A26. These calculations purport to show the long-run implications of raising electricity prices solely as a means for reducing electricity usage in the year 2024. Given the price elasticity of electric demand employed (-0.7), an approximate 28% increase in electric rates over this period would leave usage 20% lower than would otherwise prevail --- all else held constant. Since the elasticity I employ is less than 1, gross revenues collected by the utility would increase. It should be noted that since usage is reduced, net revenues realized by the utility would rise by a much greater amount than

the calculated gross revenue increase. The utility no longer incurs the costs to produce the electricity that is saved by this reduction in usage.

Q27. WOULD SUCH A PRICING POLICY REPRESENT SOUND PUBLIC POLICY?

A27. Economists generally do not recommend raising prices solely for the purpose of reducing the quantity demanded of a good or service. Sometimes a good or service is not deemed good for society to consume, and some form of "sin tax" is imposed in some manner to discourage consumption. If electricity usage was deemed by policy makers to be a "bad" rather than a "good," then increasing prices for the sake of reducing consumption would be appropriate.

Q28 IS THERE A PRICING POLICY THAT CAN ACHIEVE SOUND PUBLIC POLICY?

A28. It depends on one's point of view.

The marginal cost based pricing regime advocated by many economists is not directed at saving electricity just for the sake of saving electricity. Rather, the objective is to price electricity correctly so that customers may make rational decisions --- based on the true cost of both electricity supply and electricity conservation --- regarding how much of each to purchase to meet each customer's unique requirements. The idea is not to punish customers or discourage use. Nor is the intent to encourage

use. The idea is to get the right amount of electrical consumption based on the resource cost of producing and delivering electricity.

One key problem with marginal cost pricing becomes apparent in certain utility cost environments. If utility marginal costs appear to be above average costs, pricing all electricity consumed at marginal cost will produce excess earnings for the utility. That is not the intent of advocates of marginal cost pricing. Nor would the intent be to have utilities under-collect should marginal costs be below average costs and rates be set on the basis of those lower average costs. Moreover, there are also other substantial barriers to implementing marginal cost pricing in Virginia. First, customers will be dissatisfied if such a regime causes their bill to increase. Second, the numerous adjustment clauses currently included and likely to be added to Virginia utilities' retail electric bills make it very difficult for customers to determine what it actually costs to consume an additional kWh of electric service and then compare that cost to a conservation alternative. Finally, there are substantial technical competencies required to actually determine a particular utility's marginal costs for its various customer classes and rates.

Despite these impediments, the great benefit of prices appropriately set is that it allows customers to compare the true cost of electric power to the cost of conservation measures as it applies to their specific home or business. This potentially leads to truly efficient outcomes. Decentralized

decisions are made by customers based on prices produced by the free market (for conservation measures) and prices resulting from a regulatory process designed to produce electricity prices at the margin that are as close as possible to those that would prevail in a well functioning electricity market --- if that could be achieved. Prices are information that reaches every customer. Many customers can and would act on that information.

To sum up, an important question here is to what extent regulated retail electric prices in Virginia can and should be used as a means to promote cost-effective conservation. Prices can be increased to induce effective demand side management, conservation, energy efficiency, and load management actions taken by customers acting on their own behalf in the absence of utility programs. Pricing strategies can seek to move towards a regime where electric energy is priced at an appropriate measure of marginal cost. Alternatively, prices on usage sensitive rate elements can be increased for the sole purpose of discouraging electric use without an attempt to consider the resource cost of producing and delivering electricity. The major motivation for this policy direction might be that reducing electricity use is beneficial for environmental, national security, or other hard to monetize reasons. This latter strategy is an effective means of achieving a usage reduction goal because it will cause a usage reduction at relatively low cost --- beyond the cost to consumers borne in the form of increased electric rates.

While raising prices to achieve a usage reduction goal will reduce electric consumption, setting prices based on marginal cost is inconsistent with goal setting. Assuming all appropriate cost are considered in setting electric rates, marginal cost pricing is thought to result in the "correct" amount of electric usage based on the resource costs of producing and delivering electric power. Consuming the "right" amount of electricity negates the need for a consumption reduction goal.

A third basic strategy abandons price as a means to influence consumption. This strategy has consumption influenced (reduced) by centrally administered DSM/EE/DR programs run by the utility, government agency or third party. It is to these types of programs I now turn.

III. POTENTIAL IMPACTS FROM DSM/EE/DR PROGRAMS

Q29. WHAT QUESTIONS DO YOU EXPECT TO COVER IN THIS SECTION OF YOUR TESTIMONY?

A29. In the Order that initiated this proceeding, the SCC asked respondents to answer questions taken from a section numbered 10.1-1307.02 of the Code of Virginia. As discussed above, the legislatively mandated determination that the Commission must make as a result of this "formal public proceeding" requires careful analysis of detailed company specific information on marginal costs, marginal rate revenues and customer end

use equipment inventories as well as detailed information on the costs and structure of potential DSM/EE/DR programs. To the extent that such data is not presently available or there is not time enough to analyze adequately the data that is available, the Commission's determinations in this matter are necessarily less precise than what would prevail under different circumstances.

Substantial and accurate company specific data and information are required before actual program design can commence and before reasonably precise estimates of the range of potentially achievable consumption and peak load reductions for each generating electric utility can be determined. In the discovery portion of this proceeding, Staff asked respondent generating electric utilities to provide DSM/EE/DR program information and potential costs that would produce a range of consumption and peak load reductions (5% to 20%) in the year 2024. Staff also asked for the rate impacts associated with the potential program portfolios and the results of any cost-effectiveness testing. The responses of DVP, ODP, and APCo are reported below.

Staff also retained Mr. Nicholas Puga of Bates White to evaluate the cost and benefits of potential DSM/EE/DR program portfolios reported by the three generating electric utilities in response to Staff interrogatories. Mr. Puga has filed testimony on behalf of Staff in this proceeding.

Q30. PLEASE REVIEW THE INFORMATION PROVIDED TO STAFF IN RESPONSE TO STAFF'S DISCOVERY.

A30. The purpose of Staff's questions were to discover a range of potentially achievable consumption and peak load reductions for each generating electric utility in the Commonwealth along with the cost and rate impacts expected to accompany the range of reductions. Staff believes that the utilities themselves were a reasonable source of information to answer this question. The responses are reported separately for each generating electric utility below.

DVP

DVP responded to Staff's interrogatory with information relative to a 2.8% decrease in energy sales versus the kWh sales level that would otherwise prevail in 2024. Such a reduction was estimated by the company to cost \$2.073 billion for a portfolio of energy efficiency and demand response programs and raise rates to consumers in a range centered on one-quarter of one cent per kWh.

Trying to answer Staff's question about a range of savings from 5% to 20%, DVP tendered energy reductions, dollars spent and rate impacts for Florida Power and Light programs offered from 1992 through 2007. These results are summarized in the following table:

DVP: Table 6

<u>Energy Reduction</u>	<u>2.8%</u>	<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
Program Cost	\$ 1,227,516,000	\$ 1,596,265,000	\$3,192,530,000	\$4,788,796,000	\$6,385,061,000
Saved 2024 MWH	3,165,148	5,652,050	11,304,100	16,956,150	22,608,200
Rate Impact (per kWh)	\$ 0.0024	\$ 0.0150	\$ 0.0330	\$ 0.0520	\$ 0.0730
<u>Capacity Reduction</u>	<u>2.8%</u>	<u>5.0%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
Program Cost	\$ 845,772,000	\$ 1,885,407,000	\$3,770,815,000	\$5,656,222,000	\$7,541,630,000
Saved 2024 MW	631	1,101	2,203	3,304	4,405
Rate Impact (per kWh)	\$ 0.0024	\$ 0.017	\$ 0.035	\$ 0.052	\$ 0.069

ODP

In April, 2008, Kentucky Utilities (“KU”) received approval to implement a seven-year \$182 million portfolio of DSM/EE programs in Kentucky. In Virginia, KU does business as ODP. ODP answered the question posed in Staff’s interrogatory based on scaling KU’s DSM/EE offerings to the much smaller Virginia service territory of ODP.

ODP: Table 7

<u>Energy Reduction</u>		<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
Program Cost		\$ 19,261,925	\$ 38,523,851	\$ 57,785,776	\$ 77,047,701
Rate Impact (per kWh)	Res	\$ 0.0300	\$ 0.0610	\$ 0.0910	\$ 0.1220
Rate Impact (per kWh)	Com	\$ 0.0090	\$ 0.0180	\$ 0.0270	\$ 0.0370
Saved 2024 MWH		52,573	105,146	157,719	210,292
<u>Capacity Reduction</u>		<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
Program Cost		\$ 14,006,019	\$ 28,012,038	\$ 42,018,057	\$ 56,024,076
Rate Impact (per kWh)	Res	\$ 0.0220	\$ 0.0450	\$ 0.0670	\$ 0.0900
Rate Impact (per kWh)	Com	\$ 0.0060	\$ 0.0130	\$ 0.0190	\$ 0.0260
Saved 2024 MWH		13	25	38	50

APCo

APCo did not answer the question as asked. Instead, APCo's basic response to the question, via the direct testimony of Barry L. Thomas, was to state that the company "supports a DSM program that will result in a realistic level of savings within a 5-year program period (the period the Company recommends as an appropriate focus at this stage of the development of DSM in Virginia) and believes that is a savings of approximately 2% of APCO's 2008 Virginia energy consumption and approximately 5% of its 2008 peak load."¹⁶ APCo Witness Thomas goes on to state that "the costs of this more realistically accomplishable level of

¹⁶ Thomas direct testimony (6/30/2009) at 3 and 4.

savings is in the range of \$80-100 million for direct program and administrative costs.....”¹⁷ Finally, Mr. Thomas states that “in order to achieve higher levels of savings, customers will have to bear more risks and pay higher costs over a longer period of time.”

Q31. WHAT HAVE YOU LEARNED FROM THESE RESPONSES?

A31. First, note that Staff Witness Puga will be reviewing these responses based on his knowledge of program costs and program designs. I note the many disclaimers that accompany the responses of these generating electric utilities and I agree that precision and confidence in such estimates is justifiably in short supply. Nevertheless, a theme emerges that is consistent with economic theory.

These responses imply that DSM/EE/DR, like almost anything else, exhibits an upward sloping supply curve. In other words, the higher the goal set for reduced consumption, the more expensive it will be to achieve the goal via centrally administered efficiency programs (basically, the “low-hanging” fruit is less costly to obtain). The more expensive it will be to achieve the goal, the more likely it will be that latter units of DSM/EE/DR obtained will be more expensive than the displaced supply that could have been delivered by the electric utility grid. Since purchasing DSM/EE/DR that is less costly (by some measures) than grid supply can

¹⁷ Thomas direct testimony (6/30/2009) at 4.

put upward pressure on rates, provisioning efficiency that is more costly than grid supply will put even more upward pressure on electric rates.

IV. COST ALLOCATION ISSUES

Q32. HOW SHOULD THE COMMISSION DETERMINE A JUST AND REASONABLE RATEMAKING METHODOLOGY TO BE EMPLOYED TO QUANTIFY THE COST RESPONSIBILITY OF EACH CUSTOMER CLASS TO PAY FOR GENERATING ELECTRIC UTILITY-ADMINISTERED DEMAND-SIDE MANAGEMENT PROGRAMS?

A32. This is Commission question # 8 as set forth in the Order opening this proceeding. The most general cost allocation principle recommended by regulatory economists and others¹⁸ is that the costs of a facility ought to be allocated to those benefiting from the facility. Those benefiting from the construction of a facility may be thought of as those “causing” the facility

¹⁸ See, for example, the decision of the United States Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission, et al., v. Federal Energy Regulatory Commission, et al.*, decided August 6, 2009. Quoting from the majority decision: FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. “ ‘[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.’ *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000); *Pacific Gas & Elec. Co. v. FERC*, No. 03-1025, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004). Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.” *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004); see also *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346-47 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P. v. FERC*, *supra*, 285 F.3d at 4-5; Federal Power Act, 16 U.S.C. § 824d.

to be placed into service. This principle of "cost-causality" has been a fundamental principle of rate-making for decades.

The principle of beneficiary pays is well suited for the allocation of the costs of utility plant and associated overheads. Of course, there can be controversy surrounding the details of the cost allocation procedure. Varying degrees of judgment is required when allocating various types of facilities and associated costs to rate classes and rate elements within those rate classes. In the case of a generating station or transmission line, measures of the relative intensity of electrical use by rate class are used to apportion facility costs between various rate classes. The underlying idea is that these relative measures of electrical usage intensity serve as reasonable proxies to the relative benefits of the facility realized by various rates classes.

The cost allocation issue for DSM/EE/DR costs is often addressed in a similar manner. For example, it is often proposed that the cost of programs directed at residential customers be collected from residential customers, commercial program costs be collected from commercial customers, and industrial program costs be collected from industrial customers.¹⁹ Further, the cost of programs thought to save energy may be

¹⁹ Of course, current law in Virginia provides "opt-out" provisions for large industrial customers pursuant to Chapter 824 (House Bill 2506) of the 2009 Acts of Assembly.

collected in energy charges while the cost of programs thought to save capacity may be collected in demand charges.

Q33. DOES THIS COST ALLOCATION RATIONALE HOLD FOR DSM/EE/DR PROGRAMS?

A33. It depends on one's perspective. Consider a generation, transmission or distribution plant addition to rate base and utility revenue requirement. Depending on a number of utility or rate class specific circumstances, the additional plant may cause a near-term or long-term change in rate levels for one or more rate classes. In any case, the additional plant serves load and customers pay for the additional plant via rates that are thought to be less than the value received by ratepayers taken as a whole.

In Virginia's regulatory structure, DSM/EE/DR might be considered in a different light. First, again depending on a number of utility or rate class specific circumstances, the DSM/EE/DR program may cause a near-term or long-term change in rate levels for one or more rate classes that stem from just the change in usage levels. Such rate changes, be they up or down, may impact other non-participants via the operation of one or more of a Virginia utility's rate adjustment clauses. The point is that benefits or detriments in terms of rate changes may migrate out of the rate class at which a particular DSM/EE/DR program is directed.

A more extreme illustration of this point stems from the climate change issue. Simply put, if policy makers in Virginia determine that a

particular usage reduction goal should be implemented due to concerns about climate change, any actual benefit of that policy will accrue in and beyond Virginia reaching the global community. While Virginia policy-makers could not charge the costs of the programs that achieve the usage reduction goal to those beyond the reach of the Commonwealth's jurisdiction, virtually any intra-state allocation of the costs of those programs would stand economic muster.

While Section I of this testimony and Exhibit HMS-2 makes a case for having customers pay for their own DSM/EE, if policy-makers determine that DSM/EE is to be undertaken to address climate change concerns rather than promoting economic efficiency, then the case for having participants pay for their own DSM/EE so as to hold electric rates unchanged is considerably diminished.

Q34. WHAT ARE THE POSITIONS OF THE PARTIES REGARDING A JUST AND REASONABLE RATEMAKING METHODOLOGY TO BE EMPLOYED TO QUANTIFY THE COST RESPONSIBILITY OF EACH CUSTOMER CLASS TO PAY FOR GENERATING ELECTRIC UTILITY-ADMINISTERED DEMAND-SIDE MANAGEMENT PROGRAMS?

A34. Dominion Virginia Power and Kentucky Utilities/Old Dominion Power suggest that DSM program costs should be assigned to the participating customer class or jurisdiction. Appalachian Power Company states that

rate design or customer class cost recovery approaches should be a function of the eventual program selection and treatment of opt-out or exemptions and provides further discussion on determining which DSM costs are demand-related and which are energy-related. MeadWestvaco, the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates also believe that costs should be allocated to the customer classes that are eligible to participate and would receive the direct benefit of such programs.

The general recommendation of the parties is that the costs of the DSM/EE/DR program should be allocated to the customer class which benefits from the efficiency program. The problem is that, beyond the actual participant, it is hard to quantify the cost and benefit impacts on any particular class. If rates for the targeted class rise, it may be hard to find that the class benefits from the program --- although the actual participating customer within the class probably does benefit. And, if there are external environmental impacts from efficiency programs, those benefits can not be restricted to any particular rate class.

Q35. PLEASE RESPOND TO COMMISSION QUESTION # 9 REGARDING CLASS COST RESPONSIBILITY METHODS USED IN OTHER JURISDICTIONS AS WELL AS THE ISSUE OF "OPT-OUT" PROVISIONS FOR LARGE INDUSTRIAL CUSTOMERS.

A35. As to the latter part of the question, I note that in the 2009 legislative session, Virginia enacted legislation²⁰ to allow larger customers to avoid participating in, and paying for, utility run DSM programs under certain conditions. The balance of my present answer provides general cost allocation information as well as information as to how a series of states administer opt-out provisions for industrial customers.

Texas

According to the Texas PURA 39-905, the Commission shall "ensure that the costs associated with programs provided under this section are borne by the customer classes that receive the services under the program." Industrials served at transmission voltage levels are exempt from these programs. The utilities are able to recover the reasonable costs of providing the energy efficiency programs that were not covered through the base rates by using an Energy Efficiency Cost Recovery Factor (EECRF). The Texas General Assembly also passed BB 3693 which allows industrial customers to opt out from paying for these programs.

²⁰ The 2009 General Assembly passed House Bill 2506, which addresses class cost responsibility under Section 56-585.1 A 5 c. The statute defines criteria for certain customers to be exempt from participating in and/or paying for energy efficiency programs. House Bill 2506 includes a provision allowing large general service customers using more than 500 kW of demand from a single meter of delivery to opt out of DSM programs. Additionally, no costs related to DSM programs may be assigned to any customer having a verifiable history of more than 10 MW of demand from a single meter of delivery. The Commission is to promulgate rules and regulations to determine standards for such customers that file for such an exemption from DSM programs no later than November 15, 2009.

Kentucky

Industrial customers in Kentucky are exempt from paying for and participating in utility sponsored demand side management programs. The Kentucky Public Service Commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The Commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

North Carolina

North Carolina Session Law 2007-397 (S.B. 3) states that the costs of the demand side management programs will not be assigned to industrial customers who at their own expense implemented their own energy efficiency programs at any time in the past and who chooses not to participate. All industrials and commercial customers above a threshold usage level are able to opt-out of new programs or the full portfolio of programs if they indicate that they have invested in energy efficiency at the site.

Michigan

Michigan allows for eligible primary or secondary electric customers to be exempt from DSM/EE charges if the customer filed with its provider and implements a self-directed energy optimization plan.

Wisconsin

According to the Wisconsin Act 141, large energy customers have the opportunity to implement a self-directed energy efficiency program. This Wisconsin approach is similar to that taken in Michigan. More specifically, a large energy using customer of an energy utility may administer and fund its own energy efficiency programs. A customer that funds such a program may deduct the amount of the funding from the amount the energy utility may otherwise collect from the customer. In addition, if the customer deducts the amount of the funding from the amount the energy utility may collect from the customer, the utility shall credit the amount of the funding against the amount the energy utility is required to spend for energy efficiency projects.

South Carolina

The South Carolina Electric & Gas ("SCE&G") Company recently filed its plan for implementing utility sponsored energy efficiency and demand side management programs and for approval of a rider to recover costs associated with these programs. In the filing, SCE&G provided an opt-out provision for large commercial and industrial customers. In order to be

eligible, the customer has to certify in writing that they have conducted an energy efficiency audit within the past three years and are implementing measures that are at least equivalent in energy and demand savings to those anticipated under the Company's DSM program for the applicable customer class.

Ohio

In Ohio, mercantile customers who commit their peak demand reduction, demand response, or energy efficiency programs for integration with the electric utility's programs may apply for an exemption.

Oklahoma

Any high volume electricity user may opt out of some or all energy efficiency demand response programs by submitting notice to the director of the Public Utility Division and to the electric utility that submits the demand portfolio.

Q36. DOES THIS COMPLETE YOUR TESTIMONY?

A36. Yes.

PART B

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

PRE-FILED TESTIMONY

OF

J. NICOLAS PUGA

ON BEHALF OF THE STAFF OF

THE VIRGINIA STATE CORPORATION COMMISSION

CASE NO. PUE-2009-00023

September 9, 2009

**TESTIMONY OF NICOLAS PUGA
ON BEHALF OF THE STAFF OF THE VIRGINIA STATE
CORPORATION COMMISSION
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2009-00023**

1 **1 INTRODUCTION, QUALIFICATIONS AND PURPOSE**

2 **Q1. PLEASE STATE YOUR NAME, POSITION AND BUSINESS**
3 **ADDRESS.**

4 **A1. My name is J. Nicolas Puga. I am a Partner with Bates White, LLC**
5 **(“Bates White” or “the firm”), an economics and litigation consulting firm.**
6 **My business address is 1300 Eye Street, NW, Suite 600, Washington, DC**
7 **20005.**

8 **Q2. PLEASE SUMMARIZE YOUR QUALIFICATIONS.**

9 **A2. I have a B.S. in Electrical Engineering from Universidad de**
10 **Guanajuato in Salamanca, Mexico. I also obtained an M.S. in energy**
11 **engineering from the University of Arizona. I have over 28 years of**
12 **experience in electric and natural gas market analysis and supply and**
13 **demand-side resource planning, and I have advised various electric and**
14 **gas utilities as well as other entities. I was employed by the Comisión**
15 **Federal de Electricidad (“CFE”), the Mexican government’s vertically**
16 **integrated utility, in Special Projects from 1975 to 1977. I served as a**
17 **Research Engineer for the Instituto de Investigaciones Eléctricas, the**

1 Mexican government's Electrical Research Institute, from 1977 through
2 1980. Since 1984, I have worked as a consultant in the United States and in
3 other countries. From 1984 until 1990, I was Vice President of ANCO
4 Engineers, an energy technology consulting firm located in Culver City,
5 California. In this position, I worked on the design and implementation of
6 several large-scale utility demand-side management ("DSM") programs in
7 the United States and Australia. In 1990, I joined Resource Management
8 International, Inc. (RMI), an international energy consulting firm, where I
9 served as Vice President, Demand-Side Management. During my
10 employment with RMI, I worked on a variety of energy efficiency ("EE")
11 and demand-side management consulting projects in the United States,
12 Canada, the Philippines, and Indonesia. From 1996 to 1999, I worked as
13 resident advisor to the Philippine Government and to electric distribution
14 utilities in demand-side management and integrated resource planning.
15 RMI was acquired by and subsequently merged into Navigant Consulting,
16 Inc., in 1999. I worked there until 2005. From 2005 to 2007, I worked as an
17 independent consultant who advised the California Energy Commission
18 on the potential for energy efficiency and combined heat and power in the
19 California-Mexico border maquiladora industry. In 2007, I joined the

1 energy practice of Bates White, LLC. While at Bates White, I have
2 reviewed PJM's use of demand response in reliability planning and
3 testified on that subject in front of this Commission. More recently, I
4 testified as to the development of demand-side resources to postpone the
5 addition of transmission capacity to maintain the reliability of the NYISO
6 electric power system. A copy of my curriculum vitae is attached as
7 Exhibit No. JNP-1.

8 **Q3. MR. PUGA, DO YOU CONSIDER YOURSELF AN EXPERT IN**
9 **ENERGY EFFICIENCY ANALYSIS?**

10 **A3.** Yes. A significant part of my professional career since 1982 has focused on
11 the analysis of applications of energy efficiency technologies to diverse
12 end-uses of energy by residential, commercial, and industrial energy
13 consumers, as well as the analysis of the incentives and programs that are
14 often necessary to advance the adoption of these technologies. In the
15 course of my 25-plus-year career, I have worked extensively in the
16 modeling of building energy use; the design and implementation of
17 commercial and industrial customer surveys; and energy auditing of
18 residential, commercial, and industrial facilities. I have also worked in
19 most aspects of the design, implementation, and evaluation of utility
20 energy efficiency and demand-management programs, including the

1 engineering, installation, and performance monitoring of energy-efficient
2 end-use technologies. As a matter of fact, utility demand-side
3 management was at the core of my professional employment through
4 1999.

5 **Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE VASCC?**

6 **A4.** Yes. I testified on behalf of the Staff of the Virginia State
7 Corporation Commission ("VASCC") in the needs analysis of the 502
8 Junction-Mt. Storm-Meadowbrook-Loudon 500 kV Transmission Line,
9 Case Nos. PUE-2007-00031 and PUE-2007-00033.

10 **Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

11 **A5.** My testimony presents the findings of my review of the generating
12 utilities' and select nonutility parties' responses to the April 30, 2009,
13 Commission Order that asks for feasible levels of EE and demand
14 response ("DR") and associated costs. In particular, my testimony
15 examines the reasonableness of the costs and benefits of proposed
16 DSM/EE/DR program portfolios reported by the three generating utilities
17 in response to the Commission's Order and Staff interrogatories. Further,
18 my testimony examines some of the statements of intervenor witnesses for
19 the Southern Environmental Law Center.

1 A secondary but equally important purpose of my testimony is to
2 attempt to define some of the terms that appear in the first question the
3 Commission asked generating utilities and other stakeholders to respond
4 to in the course of this proceeding.

5 **Q6. WHICH TERMS DO YOU BELIEVE REQUIRE DEFINITION?**

6 **A6.** The terms in Question 1 (“What is an achievable, cost-effective
7 energy conservation and demand response target that can be realistically
8 accomplished through the generating electric utility’s demand-side
9 management portfolio?”) that require clarification are those that attempt
10 to qualify the amount of energy and demand reductions that the
11 respondents might consider appropriate for the Commission to require of
12 the generating utilities in Virginia. Much effort has been spent by
13 regulators, utilities, and environmental and energy conservation
14 advocates and their consultants to arrive at the ultimate definition of these
15 terms. The following definitions are mostly consistent with definitions
16 adopted by the Electric Power Research Institute’s (“EPRI”) in one of its
17 recent reports. ¹

¹ EPRI “Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. 2010-2030, January 2009, xiii–xiv.

1 The concepts of *technical, economic, and achievable* potential of utility
2 demand-side management define the magnitude of the possible impact of
3 utility marketing and economic incentive programs on customers'
4 electricity demand and energy consumption.

5 "Technical Potential" describes the amount of energy and peak
6 demand reductions that would result if all homes and businesses were to
7 adopt the most efficient, commercially available technologies and
8 measures regardless of cost. Cost-effectiveness and market acceptance
9 considerations are not included.

10 "Economic Potential" describes the amount of energy and peak
11 demand reductions that would result if all homes and businesses were to
12 adopt the most efficient, commercially available cost-effective technologies
13 and measures. That is, the portion of the technical potential that would
14 pass a cost-effectiveness screen that compares the present value of the bill
15 savings that result from the adoption of the energy efficient measures'
16 over its useful life to a given baseline. Because no incentives are
17 considered, an implicit assumption is that customers will maintain energy
18 efficient measures until those measures reach the end of their useful lives.

1 “Achievable Potential” describes that part of economic potential
2 that can be achieved by taking into account the various barriers to the
3 adoption of the energy efficient or demand reduction measures. Even if
4 utility programs could be funded to a level that would perfectly inform
5 customers about energy efficient choices and give them an incentive large
6 enough to put energy efficient measures on an economic par with the
7 baseline, some customers would still refuse to adopt such measures.
8 Customers’ reasons for not doing so might include cost, esthetics,
9 functionality, or a reluctance to be inconvenienced.

10 The “Maximum Achievable Potential” takes these elemental
11 customer barriers into account, but it does not take into account other
12 existing market, financial, political, and regulatory barriers, including the
13 impossibility of providing all customers with perfect information about
14 their efficient choices and the fact that utilities never have unlimited
15 budgets for DSM programs. The “Realistic Achievable Potential” is the
16 result of considering all of these additional barriers, and thus, it represents
17 a forecast of the most likely customer behavior in utility program
18 participation.

19

1 **Q7. PLEASE IDENTIFY THE WITNESSES WHOSE TESTIMONY YOU**
2 **ADDRESS IN YOUR TESTIMONY.**

3 **A7.** My review and testimony addresses the testimony of the following:
4 • Virginia Electric Power Company (“DVP”) witness Shannon L. Venable
5 • Kentucky Utilities Company d/b/a Old Dominion Power Company
6 (“KU/ODP”) witness Lonnie E. Bellar
7 • Appalachian Power Company (“APCo”) witnesses Barry L. Thomas ,
8 Fred D. Nichols, and William K. Castle
9 • Southern Environmental Law Center, Appalachian Voices, and the
10 Virginia Chapter of the Sierra Club (“SELC ET AL”) witnesses Jeff
11 Loiter and William Steinhurst.

12 **2 VIRGINIA ELECTRIC POWER COMPANY**

13 **Q8. PLEASE SUMMARIZE DVP’S RESPONSE TO THE VASCC’S**
14 **COMMISSION QUESTION REGARDING FEASIBLE LEVELS OF EE**
15 **AND DR AND ITS COSTS.**

16 **A8.** DVP’s response rests solely on the testimony of witness Shannon L.
17 Venable. The primary focus of witness Venable’s testimony is to adopt
18 DVP’s most recent 15-year load forecast as the basis of the utility’s
19 portfolio of DSM programs filed as of July 30, 2009, and its biennial
20 Integrated Resource Plan (“IRP”), which must be filed on September 1,
21 2009. Her testimony also stated that DVP believes that the goal of

1 reducing retail energy consumption in 2022 by 10% of 2006 levels set by
2 the Virginia General Assembly is attainable in a cost-effective manner.²
3 She established that an initial Portfolio of DSM Programs that will be filed
4 by DVP on or after July 1, 2009, would aim to achieve energy and capacity
5 reductions over a 15-year period that are equivalent to approximately one
6 third of the 10% goal. In her testimony, witness Venable also stated that,
7 given the difficulty in predicting the speed of the economic recovery,
8 technological change, etc., DVP's preference is to establish goals based on
9 historical consumption instead of on a load forecast. Witness Venable also
10 expressed DVP's wish to establish interim targets to meet the 10% goal in
11 order to assess "achievability" and "cost-effectiveness" and to feed the
12 results of the associated evaluations into the utility's IRP process.

13 **Q9. DID MS. VENABLE DESCRIBE THE PORTFOLIO OF DSM**
14 **PROGRAMS?**

15 **A9.** No, Ms. Venable did not provide any description of the type of
16 programs to be filed on or after July 1, 2009. However, I have reviewed
17 some of the responses of DVP to Staff interrogatories regarding the type of
18 programs and/or measures that the utility would propose to meet a

² Direct Testimony of Shannon L. Venable for Virginia Electric and Power Company in Case No. PUE-2009-00023, page 3, at 18.

1 hypothetical goal of 5% of the utility forecasted energy throughput for
2 year 2024.³ In responding to the Staff question, DVP submitted a
3 summary table of the company's draft DSM portfolio of programs. This
4 table showed full deployment costs by 2024, projected MW reductions in
5 2024, and projected GWH savings in the same year.

6 **Q10. CAN YOU PLEASE SUMMARIZE AND COMMENT ON YOUR**
7 **UNDERSTANDING OF DVP'S DSM PROGRAM PORTFOLIO?**

8 **A10.** I have not had the opportunity to review in detail DVP's DSM
9 program filing under Case No. PUE-2009-00081, but I do have some
10 observations regarding the makeup of the portfolio and the possible
11 interactions between some of the portfolio's component programs.
12 DVP's DSM program portfolio includes programs aimed at reducing
13 demand and energy use by residential, commercial/institutional, and
14 industrial customers. Program savings and costs in 2024, reproduced
15 from DVP's response to Staff questions are presented in tabular form in
16 Exhibit JNP-2.² DVP's portfolio includes an air conditioning cycling
17 program (peak shaving), a commercial distributed generation program,
18 and a curtailment service program. The latter two programs are primarily

³ Virginia Electric Power Company Case No. PUE-2009-00023, Staff of the State Corporation Commission, Second Set, Question. No.6.

1 demand response programs. The energy efficiency programs are aimed at
2 two of the key energy end-uses in residential and commercial buildings:
3 lighting and space conditioning. The portfolio also includes a residential
4 refrigeration turn-in program, a residential new construction program,
5 and a low-income program. By and large, programs such as these have
6 been and continue to be successfully fielded in many other jurisdictions,
7 as can be observed in Exhibit JNP-3. If the economy turns around and
8 disposable income recovers, such programs, if properly designed, are
9 likely to work well in Virginia. However, one program, the Voltage
10 Conservation Program, stands out from the others for several reasons that
11 I believe make the portfolio unbalanced and risky in Virginia.

12 **Q11. COULD YOU PLEASE EXPLAIN HOW A CONSERVATION VOLTAGE**
13 **REDUCTION PROGRAM WORKS?**

14 **A11.** Conservation Voltage Reduction or Regulation ("CVR") is a
15 conservation technique that has been investigated, tried, and occasionally
16 adopted by a number of utilities over the past 30 years. Several utilities in
17 the Pacific Northwest, in particular Snohomish County Public Utility
18 District in Washington State, have applied CVR to their distribution

1 systems as a conservation technique.⁴ CVR conserves energy by reducing
2 distribution system losses and by reducing the energy consumption of
3 some end-use loads by lowering the distribution voltage within the
4 minimum service voltage standards. The effectiveness of a CVR program
5 will depend on the design of the distribution network and on the
6 composition of the load connected to it.

7 **Q12. WHAT IS THE IMPORTANCE OF THE COMPOSITION OF THE**
8 **LOAD?**

9 **A12.** A limitation to the effectiveness of CVR is that many consumer end-
10 use loads do not use less energy at reduced voltages. Only resistive loads
11 do (and electromagnetic lighting ballasts—but I'll come back to them
12 later). Thus, incandescent lamps, resistive electric ranges and ovens,
13 water heater elements, electric clothes dryers, and resistance space heaters
14 (including baseboard heaters and the strip back-up heating elements for
15 heat pumps) draw less instantaneous power at reduced voltage; the power
16 consumed by these types of loads is proportional to the square of the
17 voltage.

⁴ Distribution Efficiency Initiative - Northwest Energy Efficiency Alliance, December 2007, page 1-3.

1 Unfortunately, with the exception of incandescent lamps, all other
2 resistive loads (mostly used for heating) are thermostatically controlled
3 and thus simply run longer cycles to satisfy their heating loads when the
4 voltage is lowered. In other words, since a thermostat turns a heater off
5 when the desired temperature is reached, as lower voltage reduces the
6 amount of heat put out by the heating element, it will take longer to reach
7 the desired temperature, and the device will stay on longer. The overall
8 amount of heat needed and the electric energy used to produce it will
9 remain the same.

10 Other consumer loads, such as induction motors, draw more
11 current as voltage is reduced—that is, their load remains constant or even
12 increases slightly when internal motor losses are taken into account, thus
13 using more energy. These include motors that drive most fans and
14 pumps, as well as compressors that drive air conditioners, heat pumps,
15 refrigerators, and freezers.

16 Finally, electronic appliances such as televisions, computers, and
17 other entertainment equipment are all powered through voltage regulated
18 power supplies that maintain a steady supply of power to the appliance
19 regardless of variations in the voltage. Consequently, electronic

1 appliances do not use less energy at reduced distribution voltages; this
2 brings me back to fluorescent lighting.

3 Fluorescent lamps, as well as other larger electric discharge lamps,
4 need a device called a ballast to limit the current running through the
5 lamp once the electric arc is established on startup. Until relatively
6 recently, fluorescent lamp ballasts used either electromagnetic ("EM") or
7 electronic technology. Electromagnetic ballasts in fluorescent lighting
8 applications have been shown to operate more efficiently (producing more
9 light with less input power) at reduced voltages. However, advances in
10 electronics have made electronic ballasts increasingly more efficient and
11 cheaper than the electromagnetic kind. Moreover, U.S. Department of
12 Energy energy-efficiency standards have effectively phased out the
13 manufacture of EM ballasts for the most common type of fluorescent
14 lamps.⁵ So, while hundreds of millions of EM ballasts remain in operation
15 in many commercial buildings, as they burn out they'll likely be replaced
16 by electronic ballasts.

17 In summary, the limited share of resistive end-use loads limits the
18 effectiveness of CVR as an end-use conservation tool. Let me explain

⁵ 10 C.F.R. Pt. 430, "Energy Conservation Program for Consumer Products: Fluorescent Lamp Ballasts Energy Conservation Standards."

1 further. Exhibit JNP-4 shows the aggregate breakdown of electricity
2 consumption by end-use in U.S. homes and commercial buildings. Of
3 course, the end-use shares in individual premises will vary depending on
4 whether the building uses natural gas or another fuel instead of electricity
5 for space heating, cooking, and clothes drying. As you can see, in
6 residential homes the share of resistive loads is usually limited to less than
7 20% of the annual load, and this percentage is even lower in most
8 commercial buildings. As the electromagnetic ballasts in existing lighting
9 fixtures are replaced by electronic ballasts, the share of load affected by
10 CVR in commercial buildings will be even lower still. The same can be
11 said for incandescent lighting in homes as incandescent bulbs are replaced
12 by compact fluorescent lamps and other new lighting technologies such as
13 LED lighting.

14 **Q13. CAN YOU NOW EXPLAIN WHY DO YOU THINK CVR INCREASES**
15 **THE RISK IN DVP'S DSM PROGRAM PORTFOLIO?**

16 **A13.** As illustrated in Exhibit JNP-2 page 2, the CVR program as
17 proposed by DVP represents a disproportionate share of both the overall
18 savings (75%) and the overall deployment costs of the energy efficiency
19 programs in the DSM program portfolio (67%). Depending on one of
20 eleven DSM programs for 75% of the expected savings of the portfolio is

1 not smart. If the program fails to deliver its predicted savings, the impact
2 on the overall portfolio's ability to meet its savings targets could be
3 dramatic. Further, as I have explained, CVR's effectiveness can vary
4 greatly from one distribution feeder to another depending on distribution
5 system design and load composition. While most of the other DSM
6 program types in DVP's portfolio are consistently relied upon to deliver
7 low-cost savings for many utilities over the years, as illustrated in Exhibit
8 JNP-3, the energy savings track record of CVR is not nearly as well
9 established. Furthermore, as I explained before, the trends in end-use
10 technology suggest that CVR is likely to become less effective over time, as
11 the technologies that respond to lower voltage with less consumption are
12 replaced by those that don't. Moreover, several other programs in DVP's
13 DSM portfolio promote technologies that will work against CVR by
14 accelerating the replacement of CVR-compatible end-use technologies,
15 and this will further reduce the energy savings from CVR. To the degree
16 that these programs are successful, the cost-effectiveness of the CVR
17 program will diminish and reduce the cost-effectiveness of the overall
18 portfolio.

19

1 **Q14. PLEASE ELABORATE**

2 **A14.** DVP's Residential Lighting Program will promote the use of CFLs
3 (which use electronic ballasts) to replace incandescent lamps. The
4 Commercial Lighting Program will promote the adoption of high-
5 efficiency ballasts, which, as we have seen, will most likely be electronic
6 and thus impervious to CVR. Finally, the Residential Heat Pump Tune-Up
7 Program, the Residential Heat Pump Upgrade Program, and the
8 Commercial HVAC Upgrade Program are likely to reduce the use of
9 resistive strip heating during the heating season and thus could reduce the
10 potential savings from CVR by lowering the duty cycle (the amount of
11 time in any one period during which the resistive heat is on). In my
12 opinion, the portfolio would be more balanced if more weight were given
13 to its energy-efficient appliance upgrade programs and less weight were
14 given to CVR. Since the whole portfolio is only expected to achieve one-
15 third of the 10% energy reduction commitment by 2022 made by DVP, the
16 share of the other programs in the portfolio must be increased anyway.

17 **Q15. MR. PUGA, ARE YOU AWARE OF ANY OTHER UTILITIES THAT ARE**
18 **PURSUIING SUCH AN AMBITIOUS CVR PROGRAM?**

19 **A15.** No.

1 **Q16. DO YOU HAVE ANY OTHER OBSERVATIONS ABOUT DVP'S**
2 **RESPONSES TO THE COMMISSION?**

3 **A16.** Yes. In light of DVP's expressed commitment to meet the 10% goal
4 retail sales reduction from 2006 levels, I find DVP's portfolio of programs
5 unsatisfactory not only for failing to propose large enough programs
6 capable of timely meeting the 10% energy reduction target but also for
7 gross overreliance on CVR, which is a seriously flawed approach to
8 reducing energy consumption (as I explained above). DVP should carry
9 out market segmentation and appliance saturation studies for the areas in
10 which it proposes to use CVR. Based on this information, DVP should
11 carry out further analysis of the true effectiveness of CVR in distribution
12 feeders with low saturation of resistive appliances, and during seasons of
13 the year during which resistive space backup heating and water heating
14 don't represent such a large share of the load.

15 **3 KENTUCKY UTILITIES/OLD DOMINION POWER COMPANY**

16 **Q17. CAN YOU PLEASE SUMMARIZE THE RESPONSES OF OLD**
17 **DOMINION POWER COMPANY?**

18 **A17.** Yes. KU/ODP's response consisted of testimony by Vice President
19 of State Regulation and Rates, Mr. Lonnie E. Bellar. In his testimony, Mr.
20 Bellar states that KU/ODP continues to believe that by virtue of not

1 owning or operating any generating assets in the state of Virginia
2 KU/ODP cannot be considered a "generating utility" for the purposes of
3 this proceeding. Mr. Bellar also attempts to put forth the case that, with
4 only 30,000 semirural customers in Virginia and negative load growth,
5 there is little justification for implementing DSM. Instead Mr. Bellar asks
6 the Commission to consider it enough that KU and its sister company
7 LG&E carry out DSM/EE activities in Kentucky and that, presumably,
8 these activities reduce the need for capacity additions and benefit
9 KU/ODP's customers in Virginia.

10 **Q18. DO YOU AGREE WITH MR. BELLAR'S ASSESSMENT?**

11 **A18.** No. The results of KU/LGE in Kentucky can hardly be considered
12 in line with results achieved by utilities in other jurisdictions that have
13 successfully pursued DSM. In his testimony, Mr. Bellar explains that
14 KU/LGE expects to save 1.2% of forecasted cumulative energy sales over
15 the seven-year period between 2008 and 2014. These projected savings
16 are quite modest compared to the median achievable potential savings per
17 year (1.2% of retail electric sales) reported by the American Council for an

1 Energy Efficient Economy.⁶ Even though there are relatively few recorded
2 examples of utility DSM program portfolios with actual electricity savings
3 above 1% per year, 1.2% over seven years is clearly not an aggressive
4 pursuit of energy efficiency, nor is it clear that it would be enough to have
5 significant benefits in avoided capacity additions that would spill over to
6 KU's Virginia customers. Perhaps a more acceptable proposal would be to
7 offer KU/ODP's customers some of the same DSM programs that are
8 offered to KU's customers in Kentucky. This approach would probably
9 benefit Virginia's customers by lowering the otherwise relatively high cost
10 of administering different programs for the admittedly small 30,000
11 customers of KU/ODP in Virginia. Special care would have to be taken to
12 avoid subsidies across state lines while leveraging of the economies of
13 scale of the larger KU/LGE programs.

14 In his testimony, Mr. Bellar also states that in response to Staff
15 interrogatories, KU/ODP estimated the cost and impact on rates of
16 achieving a 5% reduction in retail energy sales by the year 2024. The
17 projected residential rate impact would be \$0.030 per kWh, and the

⁶ Steven Nadel, Anna Shipley, and R. Neal Elliott, "The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies," Proceedings of the 2004 ACEEE Summer Study on Energy Efficiency in Buildings, American Council for an Energy-Efficient Economy.

1 projected commercial rate impact would be \$0.009 per kWh. These
2 impacts are significantly higher than those implied by the DSM Cost
3 Recovery Components ("DSMRC") of the Residential and General Service
4 tariffs of KU in Kentucky: \$0.0021 per kWh and \$0.00088 per kWh
5 respectively.⁷ Admittedly, these charges are aimed at recovering costs for
6 programs with targets less than half of Mr. Bellar's hypothetical Virginia
7 DSM retail energy sales reduction goal of 5% over 15 years (1.2% over 7
8 years). However, even doubling these DSMRCs to reflect the higher
9 Virginia goals and corresponding higher program costs would likely still
10 indicate much lower impact rates. If the customers of KU/ODP in Virginia
11 could participate in DSM programs patterned after the KU Kentucky DSM
12 programs, and if these programs were jointly administered in a way to
13 take advantage of the economies of scale of KU's programs, perhaps the
14 rate impacts cited in Mr. Bellar's testimony could be lowered.

15 **4. APPALACHIAN POWER COMPANY**

16 **Q19. CAN YOU PLEASE COMMENT ON YOUR REVIEW OF THE**
17 **RESPONSES OF APPALACHIAN POWER COMPANY?**

⁷ Adjustments to DSM Cost Recovery Components for Kentucky Utilities Company, Tenth Revision of Original Sheet No.71.4, Effective Date January 5, 2009.

1 A19. Appalachian Power Company's witnesses Barry L. Thomas, Fred D.
2 Nichols, and William K. Castle responded to the Commission's inquiry
3 regarding what is an achievable, cost-effective energy conservation target
4 that can be realistically accomplished by an APCo's DSM programs.
5 According to witness Thomas, the utility retained Summit Blue
6 Consulting, Inc, a well-known DSM/EE consulting firm, to carry out a
7 market study to assess the relative potential of various DSM programs to
8 produce various scenarios of energy and/or peak demand reduction in
9 APCo's service territory.⁸ Summit Blue was also asked to develop a
10 sample 5-year DSM Action Plan based on the DSM Potential Study, to
11 present additional information on potential program mix, estimated
12 program costs, necessary staff levels, and other general information. In his
13 testimony, witness Thomas explains that, while the Summit Blue study
14 concluded that a [higher] range of energy and demand reductions is
15 possible, the company supports a more modest DSM Program [Portfolio]
16 that would result in a realistic level of savings within an initial 5-year
17 program period; a period which APCo considers suitable to this stage of
18 development of DSM in Virginia. The proposed Portfolio would save 2%

⁸ Direct Testimony of Barry L. Thomas for Appalachian Power Company in Case No. PUE-2009-00023, at 12-15, page 3 of 13.

1 of APCo's 2008 Virginia energy consumption and approximately 5% of its
2 2008 peak load.⁹ Witness Thomas estimated the costs for such a Portfolio
3 to range between \$80 and \$100 million dollars in direct program and
4 administrative costs. The targets presented by witness Thomas differ
5 from those in Summit Blue's DSM Action Plan report (Study's Volume 1).
6 Those show higher estimates of energy and demand savings (3.07%
7 energy savings and 5.25% demand reduction with respect to 2008 figures),
8 as well as significantly higher direct program and administrative costs of
9 \$134 million. The basis for witness Thomas's estimate of \$80-\$100 million
10 program and administrative costs is not readily apparent. Further,
11 witness Thomas recommends against the imposition of specific DSM/EE
12 targets for utilities by the Commission in this proceeding, and he suggests
13 instead that DSM goals be reviewed in an appropriate timeframe
14 concurrently with the review of APCo's Integrated Resource Plan (IRP).

15 In his testimony, witness Fred D. Nichols, Manager of Consumer
16 Programs for American Electric Power Service Corporation (AEPSC),
17 describes the rationale for APCo's commissioning the Summit Blue Study,
18 including the utility's interest in identifying the estimated technical,

⁹ Id., at 21-23.

1 economic, and achievable potentials for energy efficiency and demand
2 response and related program options.¹⁰ He discusses the Study's
3 recommendations regarding implementation of energy efficiency and
4 demand response programs, program ramp up requirements, staffing, etc.
5 He correctly points out the uncertainty, assumptions and/or limitations in
6 the Study that qualify its findings. These include the reliance on
7 secondary (regional and national) building and demographic data to
8 profile APCo's Virginia customers, the use of historical program
9 participation rates and customer willingness to invest under economic
10 conditions radically different than today's, and the potential impact of
11 future building and equipment codes and standards used in the Study.
12 These concerns are sensible and legitimate, and I will address them in a
13 later section of my testimony in my review of the Summit Blue Study. Mr.
14 Nichols also discusses the internal staffing requirements of energy
15 efficiency programs implemented largely by external contractors. The
16 figure of one full-time equivalent (FTE) per \$1 to \$3 million invested in EE
17 programs, apparently based on a survey of utilities, seems reasonable;

¹⁰ Direct Testimony of Fred D. Nichols for Appalachian Power Company in Case No. PUE-2009-00023.

1 subject to the same caveats regarding the level of effort/incentives
2 necessary to achieve program participation rates and energy consumption
3 reduction impacts comparable to program benchmarks implemented
4 under better economic conditions.

5 In his testimony, William K. Castle, APCo's Director of Demand
6 Side Management and Resource Planning, describes the three DSM Cases
7 evaluated in the Summit Blue Study and their relationship to APCo's 5-
8 year DSM Action Plan.¹¹ Moreover, he explains the rationale behind the
9 basing of APCo's 5-year DSM Action Plan on the Low DSM Case, and he
10 establishes the connection between the goals of the DSM Action Plan and
11 his interpretation of "realistically accomplishable" savings. He also
12 justifies APCo's preference for shorter-term planning goals based on the
13 uncertainty introduced by energy efficiency codes and standards that
14 change the energy savings attributions away from the EE program. Mr.
15 Castle's conservative assumptions regarding the ability of APCo's EE
16 programs, in the current economic conditions, to reach the participation
17 rates of the "best practices" program approaches proposed in the Study's
18 Base Case seem reasonable.

¹¹ Direct Testimony of William K. Castle, APCo's Director of Demand Side Management and Resource Planning for Appalachian Power Company in Case No. PUE-2009-00023.

1 In my opinion, it's uncertain whether many EE programs launched prior
2 to a well-established economic recovery will even reach historical average
3 participation rates, such as the ones predicated in the Study's Low Case
4 and the basis of APCo's 5-year DSM Action Plan and that are characterized
5 by all of APCo's witnesses as "realistically accomplishable".

6 **Q20. MR. PUGA, DID YOU HAVE AN OPPORTUNITY TO REVIEW THE**
7 **SUMMIT BLUE DSM POTENTIAL STUDY COMMISSIONED BY**
8 **APPALACHIAN POWER CO.?**

9 **A20.** Yes, I have. As described by witness Castle, the Study estimates
10 the technical, economic, and achievable potential of various DSM
11 measures and describes three DSM Program portfolio cases that are
12 designed to attain different levels of energy consumption and demand
13 reductions given different spending levels:

- 14 1. A Base Case—A portfolio of programs adopting the "best
15 practices" of a group of utilities and the associated historical
16 spending and results
- 17 2. A High Case—A portfolio of programs representing the most
18 aggressive levels of spending to achieve the highest historical
19 program results

1 3. A Low Case—A portfolio of programs representing “average”

2 historical program results.

3 All three Cases’ portfolios include programs across the residential,
4 commercial, and industrial sectors. The programs, listed in Exhibit JNP-5,
5 were patterned after successful investor-owned utility and agency energy
6 efficiency and demand response programs selected by Summit Blue. The
7 Study estimates savings and demand reductions with different time
8 horizons: 3, 15, and 20 years out. At fifteen years, the Study projects
9 cumulative annual reductions of forecasted sales (at generator) from
10 energy efficiency programs of 9% (Base), 19% (High) and 6% (Low) and
11 cumulative annual net winter peak demand reductions of 11% (Base), 23%
12 (High) and 7% (Low). Demand response programs are projected as
13 reducing forecast demand of 7% (Base), 10% (High), and 5% (Low) or 274
14 MW, 412 MW and 205 MW; respectively. Estimated total costs over the 15-
15 year period are \$582.5 million (Base), \$1,260.7 million (High), and \$341.2
16 million (Low).

17 In recognition of the challenges to DSM program participation
18 presented by the current economic environment, Summit Blue also
19 developed a 5-year DSM Action Plan based on a portfolio of the same

1 EE/DR programs as the three cases but with more modest program
2 penetration expectations. The 2009 to 2013 DSM Action Plan as presented
3 in the Study would achieve cumulative net energy savings of 492,549
4 MWh (3.07% of 2008 retail sales) and a cumulative net winter peak
5 demand reduction of 199.1 MW (5.25% of 2008 winter peak demand). The
6 Study estimated the total investment by APCo in implementing the plan
7 to be \$134 million in 2009 dollars, with an estimated lifetime cost of saved
8 energy of \$0.012 per kWh (not including customer costs). This cost does
9 not include participant costs.

10 **Q21. BASED ON YOUR PROFESSIONAL EXPERIENCE, DO THE**
11 **TARGETS OF THE 5-YR DSM ACTION PLAN SEEM ACHIEVABLE?**

12 **A21.** In principle, yes. The annual incremental energy savings targets of
13 the Plan seem in line with the historical achievements of many utilities
14 implementing similar EE and DR programs. For the residential sector,
15 savings targets rise from 0.30% of sector sales in the first year to 0.76% in
16 the fifth year. For the business sector (C&I), the target impacts rise from
17 0.29% to 0.81% over the same period. That is well below the energy
18 savings rates often cited by DSM advocates and only achieved by a
19 handful of utilities during good economic times. Ultimately, the severity
20 and duration of the economic downturn and the persistence of the

1 resulting home and business owner reluctance to invest in nonessentials
2 will determine the program's actual participation rates in the early years
3 of the Plan.

4 **Q22. DO YOU KNOW WHAT ARE THE TYPICAL RESULTS OF UTILITY
5 DSM PROGRAMS THESE DAYS?**

6 **A22.** As I cited earlier in my testimony, there are few utilities with actual
7 annual energy savings, expressed as percentage of retail sales, above 1.0%.
8 Of the 63 investor-owned utilities that reported DSM results to the Energy
9 Information Administration (EIA) in 2007,¹² only 9 had savings above 1%,
10 17 saved between 1% and 0.3%, and the remaining 37 utilities saved less
11 than 0.3%. The distribution of the results of these 63 utilities can be
12 observed in Exhibit JNP-6. It's important to note that the information
13 collected by the EIA is self-reported by the responding utilities and that
14 the EIA makes no effort to verify the accuracy of the data collected.

15 **Q23. DID YOU AGREE WITH SUMMIT BLUE'S METHODOLOGY TO
16 ESTIMATE THE TECHNICAL, ECONOMIC AND ACHIEVABLE
17 ENERGY SAVINGS POTENTIAL?**

18 **A23.** Yes. In principle, the methodology adopted by Summit Blue to find
19 the technical potential is in principle correct and quite thorough.

¹² Energy Information Administration (EIA) database for Demand Side Management (DSM) filed under Form EIA-861 file 3 year 2007.
<http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

1 However, as in many of these kinds of studies, the use of inaccurate proxy
2 data, in lieu of area-specific building and appliance saturation survey
3 data, can introduce uncertainty to the potential estimate. While APCo did
4 carry out residential appliance saturation surveys that were used in the
5 Study, that was not the case for the analysis of the commercial and
6 industrial sectors. While the sources of all inputs to the technical potential
7 analysis were mostly well documented in the report,¹³ I found no evidence
8 of other primary research that was used to obtain the detailed information
9 relating to the current saturation of electric energy efficiency measures in
10 the APCo service territory. Because no Virginia or APCo-specific
11 information on building stocks by size, construction type, age, etc.; or on
12 appliance stocks by type, age, and efficiency were available; the analyses
13 relied on regional and national data and professional judgment. The
14 applicability of each technology to building stock type and technology
15 vintage segments was duly taken into consideration in the analysis. All
16 weather-sensitive end-use consumption impacts were modeled by using
17 building e-Quest, a building energy use analysis tool maintained by the

¹³ Vol. 3: Appalachian Power Co – Virginia DSM Action Plan and Potential Study Appendices, Appendix F – SB-RAM Input summary & Measure Tracking Summary, page F-2, June 23, 2009.

1 Lawrence Berkeley Laboratories, with the support of the largest public
2 and investor-owned utilities in California.

3 **Q24. PLEASE CONTINUE**

4 **A24.** In order to estimate which portion of the technical potential is
5 economically viable, and thus establish the economic potential, Summit
6 Blue applied a cost-effectiveness test known as the "Total Resource Cost"
7 (TRC). This test compares the total cost of installing an energy efficiency
8 measure, including the costs incurred by the energy end-user and the
9 program administrator such as equipment, installation, O&M and
10 removal and disposal, with the benefits the measure provides, including
11 potential reductions in the price of the energy, water saved, and tax
12 credits. The measures' incremental, incentive, and administrative costs
13 were drawn from the DEER database. The measures' lives were taken
14 from e-Quest. T&D losses and avoided costs for energy and demand were
15 supplied by APCo.

16 Summit Blue ultimately estimated the market potential for each of
17 the three Cases by applying empirical adoption rates as a function of
18 customer simple payback. This is an adoption model that determines the
19 speed at which each technology enters the market and that includes a

1 diffusion formula to account for willingness and awareness of the
2 technology. None of these models are properly documented in the Study
3 reports, and thus they remain open to question by this reviewer. This is
4 not a minor issue, because the market potential ultimately determines the
5 actual realizable potential for each program.

6 **2 SOUTHERN ENVIRONMENTAL LAW CENTER ET AL**

7 **Q25. DID YOU HAVE THE OPPORTUNITY TO REVIEW THE RESPONSE**
8 **OF SOUTHERN ENVIRONMENTAL LAW CENTER ET AL?**

9 **A25.** Yes. I would like to comment on a recommendation made by SELC
10 witness William Steinhurst to the Commission regarding the need to
11 require that utility energy efficiency programs be designed and delivered
12 in a manner that prevents cream-skimming or the creation of lost
13 opportunities.¹⁴ While I wholly concur with Witness Steinhurst on the
14 need to prevent lost opportunities in a given building or facility by
15 arbitrarily limiting the number of lights or appliances per premise or by
16 limiting the number of times a customer can participate in different
17 programs, I would like to alert the Commission to the practice of "savings
18 bundling." This is a practice whereby a customer is sold an expensive

¹⁴ Direct Testimony of William Steinhurst on behalf of the Southern Environmental Center, et al. in Case No. PUE-2009-00023, pp. 48-49.

1 piece of equipment that produces little savings per se, but which is
2 packaged with other conservation measures that do save energy at little or
3 no cost. I have reviewed numerous proposals for "comprehensive
4 approaches" to saving energy in which all energy savings came from
5 corrective maintenance in a building's lighting and HVAC systems. This
6 was a commonly undertaken by energy service companies during the
7 1980s and 1990s to take advantage of utilities' custom C/I energy
8 conservation programs. While Mr. Steinhurt took care to describe lost
9 opportunities as those less cost-effective measures thus assuring that all
10 measures meet minimum cost-effectiveness criteria, the program funds
11 allocated to those measures could have been made available to other more
12 cost-effective opportunities in other facilities, thus decreasing the overall
13 cost-effectiveness of the program. Further, forcing comprehensive
14 bundles of measures forces the customer to invest in measures that fail to
15 meet the participating firm's hurdle rate.

16 Witness Jeff Loiter's testimony presents an assessment of the
17 potential for energy efficiency savings and demand reductions that by-
18 and-large fails to consider the impact of the current recession on load
19 growth and DSM program participation by Virginia consumers. His

1 savings estimates for Virginia are predicated on a simplified 2010–2025
2 load forecast based on a 2010 energy sales estimate of 117,351 GWh with
3 constant 2% annual growth for the following 15 years.¹⁵ In my opinion,
4 the base year and the annual growth rate of his forecast are unrealistically
5 high for the following reasons: First, the 2010 energy retail sales datum in
6 his forecast is 6.6% higher than Virginia’s 2008 electricity sales of 110,023
7 GWh,¹⁶ but recent trends in electricity consumption don’t support that
8 much growth. EIA’s Monthly Energy Outlook shows that Virginia’s
9 January 2009–May 2009 electricity sales have only grown 0.31% over 2008
10 sales for the same period. The EIA’s Short Term Energy Outlook of
11 August 11, 2009 predicts: *“Total retail sales of electricity are projected to decline*
12 *by 2.7 percent throughout the United States during 2009. Sales in the industrial*
13 *sector are projected to decrease by about 10 percent this year due to the weak*
14 *economy. . . . Total electricity consumption is expected to rise by 0.8 percent in*
15 *2010.”*

16 In addition to using an unrealistically high electricity sales forecast
17 as the basis for his potential assessment, Mr. Loiter proposes savings

¹⁵ Direct Testimony of Jeff Loiter on behalf of the Southern Environmental Center, et al. in Case No. PUE-2009-00023, p. 7.

¹⁶ Table 5.4.B. Retail Sales of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2008, Electric Power Monthly: Retail Sales of Electricity to Ultimate Customers by End-Use Sector, by State, Energy Information Administration.

1 targets that are predicated on Virginia utilities reaching an annual savings
2 target of 1.3% of retail sales in only four years, and he adds the same
3 amount of savings each year for the next eleven years. As I have
4 explained in prior sections of my testimony, an annual savings rate of 1.3%
5 of retail sales represents a savings rate historically achieved by only a very
6 small number of utilities during years of strong economic growth. Under
7 the current and potentially lingering economic conditions, achieving that
8 rate cost-effectively may prove to be extremely difficult, if not impossible.

9 It should also be noted that by relying on a forecast of electricity
10 sales by all electricity retail suppliers in Virginia, including those outside
11 of the Commission's jurisdiction (e.g., cooperatives and municipalities),
12 the adoption of Mr. Loiter's "Realistically Accomplishable DSM Savings in
13 Virginia" numerical targets would require actions by the Virginia State
14 government well beyond the Commission's jurisdiction.

15 **Q26. DOES THIS CONCLUDE YOUR TESTIMONY?**

16 **A26. Yes.**

J. Nicolás Puga, M.S.

Partner

Summary of experience

J. Nicolás Puga has more than 25 years of experience in electric power and natural gas markets analysis, generation and transmission project development, utility resource supply planning, and renewable energy resource development. Mr. Puga has extensive experience in designing and implementing strategies for the introduction and promotion of energy efficiency policies and programs sponsored by electric and gas utilities. He has contributed to or authored energy efficiency policies and regulations, and he has worked on the planning, design, implementation, and evaluation of electric and gas utilities' large commercial and industrial energy-efficiency improvement and customer care programs. In the area of market research, he has conducted studies on the delivery channels of energy efficient equipment, the role of trade allies, and the assessment of energy consumer needs, attitudes, and perceptions.

Mr. Puga has a B.Sc. in Electrical Engineering and a M.Sc. in Energy Engineering from the University of Arizona. During his consulting career, he has advised numerous private and public sector clients in the United States, Canada, Mexico, Argentina, Chile, Venezuela, Colombia, Philippines, and Australia. Mr. Puga is a fluent speaker of technical and conversational English and Spanish.

Areas of expertise

- Energy policy
- Supply and demand assessment
- Utility resource planning
- Project development
- Load management and energy efficiency
- Renewable energy

Selected industry, government, and business consulting experience

- Expert witness appearing in licensing proceedings of the New York Public Service Commission (NYPSC) with respect to the application of New York Regional

Interconnect, Inc. (NYRI) to construct and maintain a 190-mile, 1,200 MW HVDC transmission line. The main focus of the testimony was the limitations of energy efficiency and demand-response programs as alternatives to the proposed transmission line.

- Energy Supply and Demand Assessment for the Border Region – Consultant Report. Researched and analyzed electricity and natural gas supply and demand forecasts and infrastructure development for the California-Baja California Norte region. Drafted Baja California sections of the Consultant Report prepared for the California Energy Commission within the 2005 Integrated Energy Policy Report preparation process. Presented the corresponding sections of the Consultant Report at the 2005 Energy Policy Report Committee California-México Border Energy Workshop
- Coordination of Activities in Support of US-México Cross-Border SENER-CEC Collaboration. Conceptualized and designed a process to establish a collaborative effort between the California Energy Commission (CEC) and the Mexican government's energy agencies to implement certain border policy options defined in the CEC's 2005 Integrated Energy policy Report (IEPR). Mr. Puga designed the roadmap for the collaborative process, including its goals and objectives and an implementation timeline. He suggested the topics to be discussed, facilitated the discussions, and drafted the preliminary language for the SENER-CEC collaboration agreement
- Analyzed the necessary conditions to deliver renewable energy from northern Baja California to California, evaluating the status of existing and anticipated energy infrastructure on the Mexico side of the California-Baja California border. Developed growth projections and analyzed energy infrastructure options for Baja California, including the potential for development of renewable energy generation, treatment of out-of-country renewable resources under the California RPS eligibility guidelines, and the eligibility of energy-for-export wind generation projects in Mexico for Clean Development Mechanism (CDM) certification
- As resident project manager of a three-year advisory project, Mr. Puga was responsible for the conceptualization, planning, and implementation of technical assistance activities to introduce integrated resource planning and demand-side management to electric utilities in the Philippines. The activities included the following:
 - Engagement and support of key nongovernmental organizations (NGOs) interested in utility resource planning in Luzon, Mindanao, and Cebu. Although initially reluctant to abandon their confrontational stance, the NGOs collaborated and produced a DSM framework which requires active public

- participation in the DSM planning process. Local NGO capacity building involved the assistance of USAID and the Environmental Defense Fund (EDF)
- Design and management of a collaborative process involving stakeholders in the power sector to develop environmental and social externality cost “adders” for DSM cost-effectiveness calculations. Over the course of nine collaborative meetings, the proceeding known as “The Valuation of Externalities Associated with the Electric Power Sector Collaborative Process” arrived at a set of values for environmental, historical and cultural, and ecosystem damage estimates
 - Development of methods, data, and procedures to integrate DSM and IRP into the rural electrification cooperatives resource and financial planning processes. Trained 165 technical and financial managers from 119 cooperatives in Luzon, Visayas, and Mindanao
 - Development of reporting formats and data collection instruments for the submittal of resource expansion plans by generators and distributors to the Philippines DOE. After sector restructuring, the data was to be used by the government to assess the adequacy of the power supply and to develop the proper regulatory and/or fiscal policies
 - Development of the first four utility DSM programs in the Philippines. Supported staff of four of the largest investor-owned and cooperative utilities in data gathering, analysis, and program design and planning, inclusive of preparation of those utilities’ DSM Plan submittals to the Energy Regulatory Board for approval under the DSM Regulatory Framework
 - Development of a DSM Planning Methodology and Manual for the Rural Electric Cooperatives that was introduced through a series of regional workshops. Using these materials, the National Electrification Administration assisted over 75 electric cooperatives prepare and submit DSM Plans to the ERB
 - Training of regulatory agency personnel on the methodologies and data sources used in the preparation of DSM Plans. Using a simulated regulatory proceeding, trained utility personnel of MERALCO, VECO, CEPALCO, and BATELEC I in the presentation and defense of their DSM Plans
 - Setup a technology demonstration program in 12 industrial plants with energy conserving production process changes and energy-efficient technologies including lighting, motors, adjustable speed drives, heat-pipe/heat-pump grain dryers, heat recovery absorption chillers, and compressed air systems. Many of the technologies and/or their applications in these projects were new to the

Philippines. Measurement and verification studies of the resulting productivity and energy efficiency enhancements were carried out to document the economic value of the technologies under real operating conditions. Case study briefs were developed for each project and posted on a Philippine government website to help in the dissemination of energy efficient technologies in the industrial sector

- Leading a best practices review of over 125 U.S. DSM programs to select the best approaches to incorporate into the development of the first four utility DSM programs in the Philippines. Project staff worked side-by-side with staff of four of the largest investor-owned and cooperative utilities in data gathering, analysis, and program design and planning, inclusive of preparation of those utilities' DSM Plan submittals to the Energy Regulatory Board for approval under the DSM Regulatory Framework
- Survey of Philippine firms engaged in the supply of energy end-use equipment and engineering services to the commercial and industrial business sectors. Such services, given the proper environment and incentives, would be likely to evolve into energy service companies (ESCOs). Developed and repeatedly offered an intensive four-day seminar on the "Technical, Market and Financial Aspects of ESCO Planning and Operations" to executives of 40 prescreened potential ESCOs. As a follow-up to this workshops, facilitated a trade mission co-sponsored by the Export Council for Energy Efficiency (ECEE) and the U.S. Embassy Commercial Office to encourage U.S. ESCOs to establish joint ventures with Philippine companies
- Surveyed Philippine financial institutions offering leasing products for the purposes of (1) introducing energy conservation project lending to financial institutions and (2) introducing emerging energy service companies (ESCOs) to a new source of project financing. In order to introduce potential lessors and lenders to the basics of energy conservation retrofit financing, developed a primer to the applicability of capital and operating leasing, project assessment, and risk mitigation techniques for these type of projects
- C/I/F Smart Money Program: Industrial Plant Energy Audits and Analysis, Wisconsin Electric Power Company, Milwaukee, Wisconsin. Under the Wisconsin Electric's Smart Money program, conducted energy audits of various industrial plants, including a friction surface manufacturer, a manufacturer of cellulose potting containers for seedlings, a paper mill, and a cosmetics manufacturer'. Audit services included extensive interviews with plant managers and operations personnel, analyses of electric energy-saving

opportunities identified during the site visit, and preparation of reports prioritizing the recommended measures by benefit-to-cost ratio

- Industrial Energy FinAnswer Program, PacifiCorp., California, Oregon, Washington, Arizona, Utah, Idaho, and Wyoming. Served as the contractor's quality assurance project manager for Pacific Power's multistate Industrial Energy FinAnswer Program. Directed the quality assurance team in reviewing design/bid documents produced by 29 other consultants retained by PacifiCorp. Directed the team in reviewing preliminary energy analyses of customers' end uses, providing quality control support during design and installation of the equipment and verifying and monitoring the energy performance of new or modified equipment. The incentive program offered 100 percent financing to industrial customers for using energy efficient technologies. Technologies assessed included electric motors and drives, industrial refrigeration systems, lighting systems, and compressed air systems
- C/I/F Smart Money Program, Wisconsin Electric Power Company, Milwaukee, Wisconsin. Served as technical team member for the Smart Money Program, an innovative management rebate program offered by Wisconsin Electric Power Company. This retrofit program was offered to the commercial, industrial, and agricultural customer market segments. Assisted in compiling a database of comprehensive technology performance and costs to assess the market for each technology and to determine the minimum program qualifying efficiency criteria. Technologies were also screened on the basis of ready commercial availability, performance and reliability. Rebate levels were established based on customer financial acceptability criteria (simple payback) and utility avoided costs. The marketing concepts and techniques developed for this program were distinguished as highly successful worldwide.
- C/I Off-Peak Cooling Programs, Southern California Edison Company, Los Angeles, California. Served as technical advisor to Southern California Edison on issues related to the company's commercial and industrial off-peak cooling programs. Reviewed feasibility studies of cool storage systems for various industries and institutions, including fruit and vegetable freezing and packing, meat processing, candle-making, office buildings, hospitals, schools, and correctional facilities. The cool storage systems in these plants used various media including chilled water, eutectic salts, ice, and state-of-the-art triple point carbon dioxide.
- Preliminary assessment of the feasibility of importation of electricity across the Arizona-Sonora border. A leading Mexican mining conglomerate wished to evaluate electricity supply options for a new, large mining operation in northwest México. In order to forecast the price of imported electricity, it was necessary to analyze the historical and

future wholesale prices at the nearest liquid Arizona (U.S.) market point, to identify generating plants with available capacity, and to estimate the cost of wheeling across the least congested transmission path to the U.S.-México border. As the U.S. and México power systems in that part of the border are not yet interconnected, investigated the regulatory status of pending cross-border interconnection proposals and established a chronology for critical permitting milestones. The results of the importation assessment allowed the mining company to carry out an unbiased comparison to other power supply options, including conventional and renewable self-generation and purchasing power at CFE tariffs

- Review of Electric Transmission Grid-Related Issues for Wind Power Generation Project. The La Ventosa wind electric generation project depends in large part on the operation of the transmission and distribution system connecting the Project's generating plant and the offtakers in different parts of México. On behalf of the project lenders, Mr. Puga studied numerous issues related to grid risk, including the following:
 - The incidence of shut-downs by CFE due to system emergencies
 - The possibility of grid instability due to the introduction of more wind-powered generators in the local region
 - The incidence of service interruptions in the LFC distribution area
 - Risks associated with the temporary and permanent transmission lines connecting the plant to the CFE grid
 - The condition and maintenance practices associated with local reception facilities owned by the municipalities
 - Possible requirements on the municipal offtakers to install new metering systems
 - The future stability of the pricing provisions in the project's transmission contracts
- Fuel Procurement and Risk Management Advisory for Comisión Federal de Electricidad (CFE). Participated in various capacities in developing an overall strategic plan for fuel risk management and in the design of the necessary organizational structure, processes, and systems to establish a world-class fuel procurement and risk management organization to manage all risks associated with fuel markets, foreign exchange, and interest rates. The new functional organization was adopted to satisfy the technical and financial requirements of CFE's current and future fuel purchasing needs. NCI also assisted CFE in the identification of mechanisms to transfer the benefits of CFE's improved risk management program to its industrial customers

- Mexico Power Market Analysis for Project Financing. Retained by the Senior Lenders to a combined-cycle generating facility to address the impact of recent changes in the Mexican electric and fuel markets on the performance of the plant. Over time, changes in the regional demand/supply balance, increased price volatility, and a departure from the traditional price relationships between natural gas and residual oil had all negatively impacted the projected dispatch levels and economic performance of the plant. In mid-2004, Comisión Federal de Electricidad (CFE) trimmed its demand growth projections in several regions and adjusted its generation capacity addition and retirement schedules in order to mitigate a significant short-term generation capacity overhang caused by lackluster energy sales during 2003-2004. A team of market modelers led by Mr. Puga addressed the potential impact of these changes on the dispatch and economic performance of the plant. *In order to model competing fuel behavior, the analyses included revised fuel price econometric forecasts that explicitly incorporated relationships between gas and oil prices. The revised fuel price forecasts were in turn applied to simulations of the Mexican power market using a proprietary, multi-area market model application and databases. The study revealed that a more realistic fuel price forecasting model as well as changes made by CFE to its generation expansion and retirement schedules had a salutary effect on the projected dispatch level of the facility*

Professional experience

- Partner, Bates White, LLC, September 2008 -
- Principal, Bates White, LLC, February 2007 – August 2008
- Independent Energy Advisor Washington, DC, December 2005–January 2007
- Director General, Navigant Consulting de Mexico, Navigant Consulting, Inc., 2003–2005
- Director, International Management Consulting Services, Navigant Consulting, Inc., Washington, DC, 1999–2003
- Senior Vice President, Resource Management International, Inc., Washington, DC, 1999
- Vice President, Resource Planning Division, Resource Management International, Inc., Manila, Philippines, 1996–1998
- Vice President, Demand-Side Management, Resource Management International, Inc., Sacramento, CA, 1991–1995
- Vice President, Demand-Side Management, ANCO Engineers, Inc., Culver City, CA, September 1984–April 1991

- Research Associate, University of Arizona, Department of Nuclear and Energy Engineering, Tucson, AZ, 1981–1984
- Research Engineer, Alternative Sources of Energy Division, Instituto de Investigaciones Eléctricas, Cuernavaca, Mexico, 1976–1980
- Design Engineer, Special Projects, Comisión Federal de Electricidad, Celaya, Mexico, 1975–1976

Education

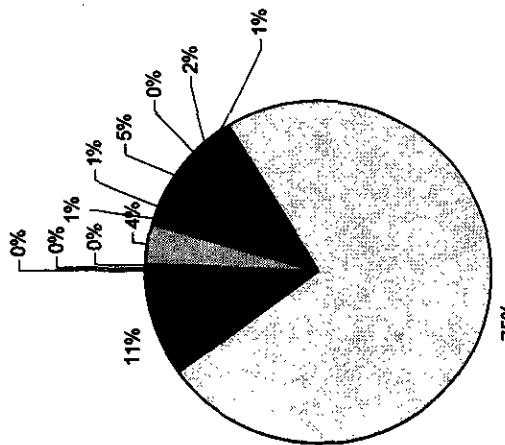
- M.S., Energy Engineering, University of Arizona
- B.S., Electrical Engineering, Universidad de Guanajuato, Salamanca, Mexico

Virginia Electric and Power Company
DSM Program Portfolio¹

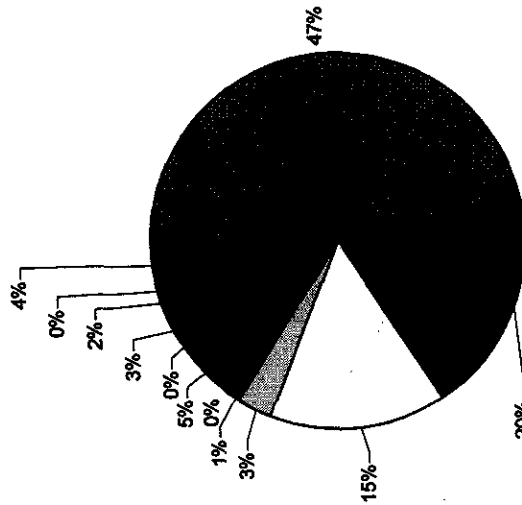
DSM Plan Programs	Projected Full Program Deployment Costs by 2024 (in Nominal Dollars \$000)	Projected MW Reduction in 2024	Projected GWh Savings in 2024
Peak Shaving Programs			
Air Conditioner Cycling Program	406,337	407	0
Total	406,337	407	0
Energy Efficiency - Demand Response Programs			
Commercial Distributed Generation Program	338,543	172	15
Curtailment Service Program	100,892	134	3
Total	439,435	306	18
Energy Efficiency Programs			
Residential Lighting Programs	14,150	27	121
Low Income Program	60,041	7	37
ENERGY STAR New Homes Program	37,790	4	41
Residential Heat Pump Tune-Up Program	121,367	47	161
Residential Refrigerator Turn-In Program	12,674	2	9
Heat Pump Upgrade Program	38,453	24	73
Commercial HVAC Upgrade Program	14,871	20	46
Voltage Conservation Program	816,929	0	2,283
Commercial Lighting Program	111,241	39	307
Total	1,307,358	170	3,078
DSM Portfolio Results	2,073,288	883	3,096
	Percent of Goal	4.0%	2.8%
	2024 Forecasted 5% Goal	1,101	5,448

(1) - Virginia Electric Power Company Case No. PUE-2009-00023, Staff of the State Corporation Commission, Second Set, Question. No.6.

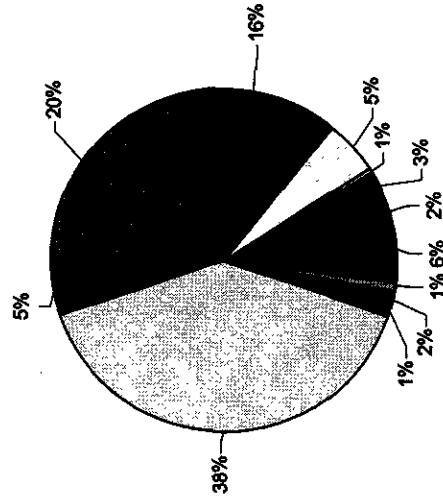
Virginia Electric and Power Company
DSM Program Portfolio



Projected GWH Savings



Projected MW Reduction



DSM Program Deployment Costs

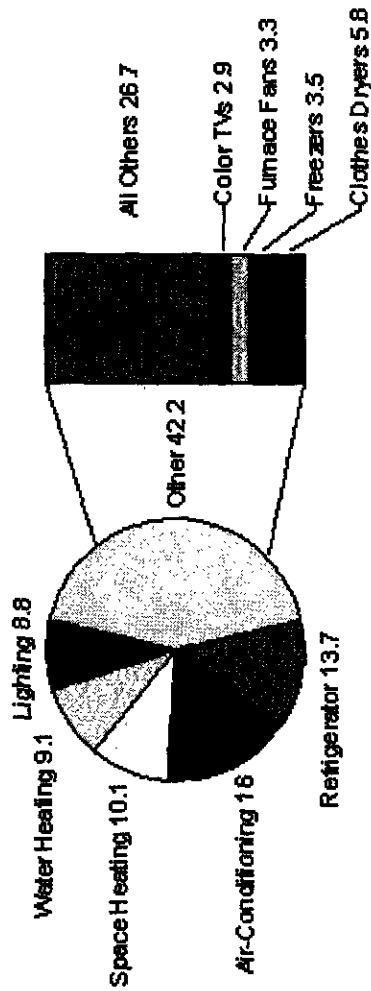
- Air Conditioner Cycling Program
- Commercial Distributed Generation Program
- Curtailment Service Program
- Residential Lighting Programs
- Low Income Program
- ENERGY STAR New Homes Program
- Residential Heat Pump Tune-Up Program
- Residential Refrigerator Turn-In Program
- Heat Pump Upgrade Program
- Commercial HVAC Upgrade Program
- Voltage Conservation Program
- Commercial Lighting Program

Widely Adopted Utility DSM Programs

Program	Efficiency (%)	Medium-term (M)	MIN Payoff	POB	SOGE	SCE	Non- Energy (MN)	Demand (DE)	Ballroom Gas & Electric (BGE)
Lighting	✓	✓	✓	✓	✓	✓	✓	✓	✓
Cooling/Heating/Roofing	✓	✓	✓	✓	✓	✓	✓	✓	✓
Building Envelope			✓	✓	✓	✓			✓
Refrigerator/Freezer Removal	✓	✓	✓	✓	✓	✓	✓	✓	✓
Energy Star Appliances	✓	✓	✓	✓	✓	✓	✓	✓	✓
Water Heating		✓	✓	✓	✓	✓	✓	✓	✓
Energy Audit		✓	✓	✓	✓	✓	✓	✓	✓
Combination		✓	✓	✓	✓	✓	✓	✓	✓
Low Income	✓	✓	✓	✓	✓	✓	✓	✓	✓
New Construction	✓	✓	✓	✓	✓	✓	✓	✓	✓
Fuel Switch	✓	✓	✓	✓	✓	✓	✓	✓	✓
Direct Load Control	✓	✓	✓	✓	✓	✓	✓	✓	✓
Lighting	✓	✓	✓	✓	✓	✓	✓	✓	✓
Cooling/Heating/Roofing	✓	✓	✓	✓	✓	✓	✓	✓	✓
Refrigeration	✓	✓	✓	✓	✓	✓	✓	✓	✓
Motors	✓	✓	✓	✓	✓	✓	✓	✓	✓
Compressed Air	✓	✓	✓	✓	✓	✓	✓	✓	✓
Custom Rebates		✓	✓	✓	✓	✓	✓	✓	✓
Energy Audit		✓	✓	✓	✓	✓	✓	✓	✓
New Construction	✓	✓	✓	✓	✓	✓	✓	✓	✓
Agriculture			✓	✓	✓	✓	✓	✓	✓
C&I Interruptible Rates			✓	✓	✓	✓	✓	✓	✓
C&I Direct Control			✓	✓	✓	✓	✓	✓	✓

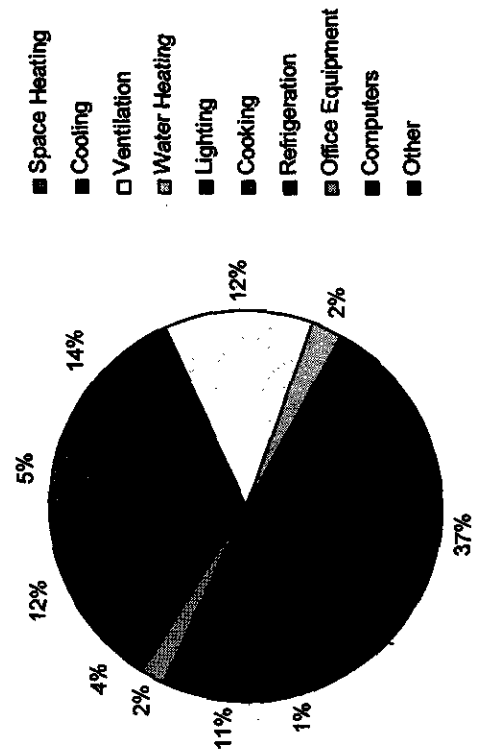
Source: Utility websites

Percent of Total Electricity Consumption in U.S. Housing Units, 2001



Source: Energy Information Administration, Form EIA-457A, B, C, E, and H of the 2001 Residential Energy Consumption Survey.

Electricity Consumption by End Use for All Buildings, 2003



Appalachian Power Company – DSM Program Portfolio

Name of Program	Description
Consumer Sector	
Efficient product	<ul style="list-style-type: none"> • Provides incentive and marketing support to retailers to increase share of Energy Star lighting and high-efficiency products. • Trains sales associates on advantages of using high-efficiency appliances and electronics to influence consumer purchasing decisions.
Appliance Recycling	<ul style="list-style-type: none"> • Targets “second” refrigerators and freezers that are still functioning but highly inefficiently. • Recycles to refrigerators and freezers provide incentives to participate. • Removes inefficient refrigerators and freezers from the market to reduce energy consumption and prevent resale of inefficient products.
Home Retrofit	<ul style="list-style-type: none"> • Produces savings by helping consumers analyze and reduce energy use through the installation of upgraded shell measures. • Provides a free online analysis followed by an audit that leads to performance retrofitting with Energy Star measures.
Low Income	<ul style="list-style-type: none"> • Recommends that low-income consumers install efficient equipment. • Provides financial assistance to cover full cost of implementation. • Educates customers as to how to reduce energy use and manage utility costs.
ENERGY STAR® New Homes	<ul style="list-style-type: none"> • Provides long-term energy savings by encouraging the construction of new homes that meet Energy Star national path efficiency standards. • Builders who participate in program will receive rebate of up to 30% of the cost of upgrade.
Residential Demand Response	<ul style="list-style-type: none"> • Establishes a Direct Load Control (DLC) program in the residential sector for HVAC and heat pumps.
Business Sector	
Prescriptive Incentive	<ul style="list-style-type: none"> • Promotes purchase of high-efficiency lighting and equipment to increase market share and installation rates. • Incentives to purchase energy efficient equipment range from 20% to 50% of incremental cost.

Name of Program	Description
Custom Incentive	<ul style="list-style-type: none"> Assists larger commercial and industrial customers with analysis and selection of high-efficiency equipment or processes that are not under the prescriptive incentive program. Includes complex and unique energy savings projects. Incentives given on per kWh energy savings & kW of demand savings for installed measures.
C&I New Construction	<ul style="list-style-type: none"> Provides design assistance to architects and designers by providing building simulation software for the design of highly efficient buildings. Provides incentives for facility owners to install high-efficiency lighting & HVAC measures.
C&I Demand Response	<ul style="list-style-type: none"> Establishes a Direct Load Control (DLC) program in the residential sector for HVAC and heat pumps and targets small C&I customers.
Multi-Sector	
General Energy Education	<ul style="list-style-type: none"> To enhance demand, creates awareness about APCo Virginia programs and educates customers on energy efficiency.
Training	<ul style="list-style-type: none"> Provides and coordinates with the C&I training program. Trains C&I facility engineers on support offered by APCo Virginia to increase energy efficiency programs customer reach.
New Pilots/Emerging Technology	<ul style="list-style-type: none"> Educates on awareness of new energy efficient technologies to capture additional savings.

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

COMMONWEALTH OF VIRGINIA,

At the relation of the
STATE CORPORATION COMMISSION

Ex Parte: In the matter of determining
achievable, cost-effective energy
conservation and demand response targets
that can be realistically be accomplished in
the Commonwealth through demand-side
management portfolios administered by
each generating electric utility identified
by Chapters 752 and 855 of the 2009 Acts
of the Virginia General Assembly

CASE NO. PUE-2009-00023

**COMMENTS
OF MEADWESTVACO CORPORATION**

Pursuant to the Virginia State Corporation Commission (the "Commission")'s Order Establishing this proceeding to fulfill the requirements of Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly dated April 30, 2009, in the above-referenced docket, MeadWestvaco Corporation ("MWV") hereby files the following Comments.

The MWV pulp and paperboard mill in Covington, VA competes in a global paper and packaging market, exporting about half of its production to markets outside of the U.S. The mill employs about 1,250 people to manufacture high quality bleached paperboard. This paperboard is converted by MWV facilities and many customer facilities into packaging for pharmaceutical, cosmetic, electronic, tobacco and food products, as well as greeting and sports cards. Collectively, the mill and the other MWV operations employ about 1,610 people in the Alleghany Highlands of Virginia. We have invested \$1.7 billion in capital at the mill from 1986 to 2005 and our capital expenditures were \$28 million in 2006, \$27.1 million in 2007 and \$31.9 million in 2008. Our capital

investments for environmental control over the past 20 years have been \$332.4 million. Our annual operating cost for environmental control is over \$46 million.

MWV's comments focus on several but not all of the questions posed by the Commission in this proceeding. The questions to which we respond support the basic principle that it is in the public interest to exempt industry from paying for utility sponsored energy efficiency efforts. Industry continually invests in energy efficiency because remaining competitive in a global marketplace demands that we be as efficient as we can cost-effectively be.

Q 2. What industry-recognized tests should be used in determining cost-effective consumption and peak load reductions and what relative weighting should be afforded to any test recommended for use by the respondent generating electric utility?

A 2. There are five generally accepted and standard tests used throughout the country for determining whether utility programs proposed to reduce consumption and peak load are cost effective. These five tests are described below:

- Total Resource Cost (TRC) compares the total costs and benefits of a program, including costs and benefits to the utility and the participant and the avoided costs of energy supply.
- Societal Test is similar to the TRC Test, but includes the effects of other societal benefits and costs such as environmental impacts, water savings, and national security.
- Utility Program Administrator Test Assesses benefits and costs from the program administrator's perspective (e.g. benefits of avoided fuel and operating capacity costs compared to rebates and administrative costs)

- Participant Test assesses benefits and costs from a participant's perspective (e.g. the reduction in customers' bills, incentives paid by the utility, and tax credits received as compared to out of pocket expenses such as costs of equipment purchase, operation, and maintenance.)
- Rate Impact Measure (RIM) or Non-participants Test assesses the effect of changes in revenues and operating costs caused by a program on customers' bills and rates.

*** Definitions obtained from National Action Plan for Energy Efficiency (NAPEE)

When considering industry tests, we should look for a test that examines a program's cost from the customer's perspective as well as the rate impacts associated with implementing these programs. The RIM test is the most capable out of the five tests to achieve this objective because it provides information on whether rates will need to be adjusted if a program is implemented.

The upward pressure on rates of energy efficiency programs due to the under-recovery of fixed costs results from reduced sales volumes. Customer incentives and program administrative costs add to the utility's revenue requirements and thus also contribute to the upward pressure on rates. Implementing measures that pass the RIM test will help avoid upward pressure on electricity rates. Applying the RIM test correctly is also important. It is recommended that the methodology used for implementing the RIM test should be consistent with the California Standard Practice Manual ("CSPM"; July 2002 version). The CSPM RIM test measures the difference between lost revenues (i.e., reduced gross income = load reduction X applicable rate) and avoided cost (i.e., reduced utility cost = load reduction X applicable marginal cost). To perform CSPM RIM test for an energy efficiency measure requires the customer rates and utility marginal costs to be projected over the life of the energy efficiency measure. In order to properly evaluate the energy efficiency program, the long run avoided cost projections and the long run rate projections used in the RIM test must be consistent and developed from the same underlying expansion plan and costs. Otherwise a mismatch of the rates

stream (which determines the RIM cost) and the marginal cost stream (which determines avoided costs and the RIM benefit) would create a net RIM impact (RIM cost minus RIM benefit) not related to the energy efficiency program being evaluated.

Tests such as the TRC and Societal evaluate “other resource benefits” of a program such as environmental, potential emission trading credit, job impacts, or personal income. The Societal Test also measures externalities of the program such as health, safety, and local economy. These externalities are difficult to objectively quantify. In addition, the decision of whether to incorporate externalities in electric energy efficiency and demand side management measures or programs is a policy matter for the Virginia General Assembly to determine. Therefore, inclusion of the Societal Test is inappropriate at this time. In general due to structure of the tests, more measures and programs are likely to pass the TRC test than the RIM test. This is primarily because the RIM test includes calculations of both avoided cost and lost revenue while the TRC test only includes the calculation of avoided costs.

The RIM test is the most conservative of the tests and is the only test that verifies rate impacts, all while evaluating the costs and benefits from the customers’ perspective. Since DSM reduces utility power sales, higher rates are charged to non-participating customers to recover costs that were not recovered from participating customers. This is especially true if there are no incremental sales from load growth to cover the incremental costs. The RIM test would fail those measures that would result in higher rates because the cost would outweigh the benefits for that particular measure compared to an alternative resource option such as a supply side option.

The CSPM states that there are limitations of the RIM test, but it also states that “under many conditions, revenues lost from DSM programs have to be made up by rate payers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the Programs.” (CSPM p.14) Because the RIM test helps to minimize both rates and costs for ratepayers, it is the only test which addresses customer’s concerns about upward pressure on electricity rates and should therefore have

the highest weight out of all the five tests. However energy efficiency programs or measures should not be rejected based solely on the failure of the RIM test. The Utility Test and Participant Test evaluate the energy costs and benefits for both parties involved in a fashion which is fairly easy to measure so these tests should be afforded equal weight following the RIM. The Total Resource Cost test does maximize efficiencies so it too should be considered. The Societal Test is much more likely to result in rate increases that can be very costly because they include externalities and environmental attributes which are not easily measurable. The Societal Test, if considered at all, should have the least amount out of the five tests. Again, any weighing of tests adopted by the Commission needs to balance the interests of minimizing rate impacts and maximizing efficiencies all while achieving the goal of cost effective energy consumption and peak load reductions.

Q. 3 How should the Commission define the terms “achievable,” “cost-effective,” and “be realistically accomplished” as they are used in the statute cited above?

A. 3 “Achievable” means being able to carry out and attain a desired goal by a certain amount of time. To determine if a target is achievable, one must look at their resource availability, costs, and the time that it will take to accomplish the goal. When considering a DSM program, resources may include technology development, infrastructure or the installation of specific equipment. Determining the costs of implementing and evaluating the program also needs to be considered when assessing whether the program is achievable. Timing is also an important issue. A demand response target may be achievable if the resources are both physically and technologically available and the costs can be recovered in a reasonable period of time.

“Cost effective” means that the benefits outweigh the costs of the program and that upward rate impacts associated with implementing these programs are avoided. In other words, if demand side options result in lower costs and lower rates than supply side additions, they are cost effective. Benefits (from a customer standpoint) may include overall decreases in bills, utility offered incentives, or tax credits while costs include

equipment purchase, installation, maintenance and any payments which may be awarded for the loss of revenue. Rate impacts should also be considered when determining if a program is cost effective. In order to avoid these upward pricing pressures and to determine if a measure or program is cost effective, a test such as the Rate Impact (RIM) should be primarily used. This is because DSM programs that fail the RIM test will cause rates to be higher for non-participating customers than would be the case if the utility had chosen supply-side resources instead.

“Be realistically accomplished” means evaluating the program and the target for its implementation and duration in more depth by performing additional analysis to establish the achievability and cost effectiveness of an individual measure or program. It also means that a measure or program can be successfully implemented considering the costs, the resources required and the target goals can be achieved.

Q. 4 How should the Commission determine the “public interest” in preparing a “cost benefit analysis of a demand side management program”?

A. 4 The Virginia General Assembly has appropriately determined that it is in the “public interest” to enhance the competitiveness of their industries by exempting certain industrial customers from mandatory participation in utility sponsored demand side management programs and for paying for the costs of these programs. This policy recognizes that industry does not need an incentive to engage in cost effective energy efficiency efforts as the implementation of energy efficiency measures is a standard and normal practice within industry. This policy also recognizes that it would be fundamentally unfair and not in the public interest to ask industrial customers to fund energy efficiency improvements of their competitors’ facilities located in the same utility service territory or to create a competitive disadvantage for industries in Virginia that are competing with facilities in other states which have exempted their industrial customers from paying these costs.

Over the past 30 years, the paper and forest products industry has steadily improved their energy performance. Fossil fuels and purchased energy use per ton of

product decreased by 9.2 percent in the industry just between 2004 and 2006 and by 56 percent between 1972 and 2006. Since 1972, the industry has reduced the total amount of energy needed to produce a ton of saleable paper by 27%. Pulp and paper mills and wood products production facilities are unique in their utilization of renewable biomass fuels, which has enabled them to reduce their fossil fuel use. In 2006, renewable energy provided 64 percent of pulp and paper mills.

As shown by the statistics above, global competition is the greatest disciplinarian of behavior and investment decisions. Investment in energy efficiency is absolutely necessary for us to remain viable in the competitive market for our products. Over the past five years alone, MWV has voluntarily spent over \$15 million in capital dollars on energy efficiency projects at our Covington mill. These projects were selected based on overall internal rate of return criteria and have resulted in energy use reductions of 672,096 million Btu per year. A sampling of the projects includes: thermal load reduction and controls, evaporator improvements, condensate heat capture systems on boilers, boiler high efficiency soot blower nozzles, and condensate heat recovery on paper machines. MWV believes we can more cost effectively reduce our energy use ourselves with our funds rather than relying on and paying for utility sponsored programs which may not be as effective in realizing the expected returns for the dollars expended.

Given our voluntary efforts and financial commitments toward achieving cost effective energy efficiency, we support and agree with the Virginia General Assembly's decision in declaring that exemptions for certain customers is in the public interest. This decision will enable us to continue to make investments in higher value projects which make the most sense for our mill.

With regard to customers not included in the exemption, the Commission should determine the "public interest" by having energy efficiency measures for those customers judged on an individual basis rather than on a program basis (several measures) or a total portfolio basis (several programs). Individual measures should be able to stand on their own when it comes to screening and evaluation. Screening done on a program basis is

less rigorous than screening on an individual measure basis and with the former, there is the possibility that a less desirable measure would be implemented. The potential to accept programs which cannot pass screening tests on their own is also present when program portfolios are evaluated altogether. Judging measures on an individual basis is important when determining cost effectiveness through a test or combination of tests. It would be difficult to ascertain the true cost and benefits of a measure if it is grouped with other measures in a program. A measure with a benefit/cost ratio greater than one means that resultant rates will be lower with the measure implemented than with an alternative resource option. There is a possibility that an individual measure with a benefit/cost ratio less than one could pass the screening process if it were included in a program or portfolio of programs that overall has a ratio greater than one. This could lead to a result that was not in the public interest because resultant rates would be higher than they needed to be.

Q. 8 How should the Commission “determine a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility administered demand side management programs”?

A 8. Regulated rates that are just and reasonable should reflect the costs of the services provided to customers. The first step in this process is for the utility to prepare a cost of service study in support of rate actions before the Commission. The primary purpose for cost of service analysis is to enable the measurement of rate of return by class of customers (residential, general service, large power etc.). Embedded cost of service studies based on test year operations provide the most widely accepted method for determining the relative fairness of a utility’s series of rate schedules. Accurate costing by detailed cost of service category within each class also provides vital information in terms of the various provisions of individual’s rate schedules. Cost of service studies are generally performed in accordance with the procedures described in the National Association of Regulatory Utility Commissioners (NARUC) Cost Allocation Manual.

These procedures can be thought of as a three step process. The three steps are functionalization, classification and allocation.

Functionalization is the process where rate base, revenue and expense items are assigned to functions according to each item's cost causation. Classification is the process where previously functionalized cost data are categorized by their most appropriate cost causation factors. The cost causation factors are classified as being demand, energy, customer or revenue related. Allocation is the process where the functionalized and classified costs are allocated or apportioned among the various customer classes by arrays of numbers referred to as allocation factors. This involves the development of demand, energy, customer and revenue allocation factors. Implementation of this methodology results in utilities recovering their fixed costs from the customer classes through the customer charge, demand charges, and a component of the energy charge.

With regard to utility administered demand side management programs, since programs are designed for specific customer classes, the cost should be allocated to those customer classes. This is consistent with the cost causation principles and can be accomplished in setting base rates. Since the Virginia General Assembly has determined that it is in the public interest to exempt certain industrial customers in Virginia from paying for the cost of these programs (including lost revenues), it would be reasonable to create a new customer class which would only include those customers. This would enable the utility to more easily recover costs from the customer class that receive benefits from the measures or programs. An alternative is to develop a specific customer class rider which would recover the costs incurred by that customer class. Industrial customers that are automatically exempt by law or who petition the Commission to become exempt would not be assessed a rider on their power bill.

Q. 9 What “class cost responsibility methods [are] used in other jurisdictions”, and “would [it] be in the public interest for the Commonwealth to have a similar policy”

to other jurisdictions that permit certain customers to be exempt from participating in and/or paying for a utility's demand side management program.

A. 9 Virginia law (HB 2506) provides that certain industrials will be exempt from participating in demand side management and mandatory energy efficiency requirements. Virginia law states that the costs of these new programs including lost revenue recovery should **not** be assigned to customers with an established demand of more than 10 megawatts from a single meter of delivery. These costs will also not be assigned to those customers using more than 500 kilowatts of demand from a single meter of delivery who choose to not participate if they have implemented or will implement their own energy efficiency measures.

Several other jurisdictions have reached similar policy conclusions to those reached in Virginia thereby permitting certain customers to be exempt from participating in and paying for a utility demand-side management or mandated energy efficiency programs. The jurisdictions with such established policies that we are aware of include Texas, Kentucky, North Carolina, Wisconsin, and Oregon. A table included as Exh.BLT-1 in the filed direct testimony of the Appalachian Power Company in this proceeding indicates that Michigan, Ohio, and Oklahoma have adopted similar policies. Although the approaches taken to achieve this public policy objective varies from one state to another, the over-arching principle is that industry typically invests in energy efficiency in order to remain competitive in a global marketplace and therefore should not be required to participate and pay for utility sponsored investments as well. If industry is forced to utilize and pay for utility mandated efficiency programs, industry would make fewer investments in energy efficiency projects that are designed to meet the facilities' specific needs.

In Texas according to the Texas PURA 39-905, the Commission shall "ensure that the costs associated with programs provided under this section are borne by the customer classes that receive the services under the program". Industrials served at transmission voltage levels are exempt from these programs. The utilities are able to

recover the reasonable costs of providing the energy efficiency programs that were not covered through the base rates by using an Energy Efficiency Cost Recovery Factor (EECRF). The Texas General Assembly had also passed HB 3693 which allows industrial customers to opt out from paying for these programs.

In Kentucky, industrial customers are exempt from paying for and participating in utility sponsored demand side management programs. The Commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The Commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

The North Carolina Session Law 2007-397 (S.B. 3) states that the costs of the demand side management programs will not be assigned to industrial customers who at their own expense implemented their own energy efficiency programs at any time in the past and who chooses not to participate. All industrials and commercial customers above a threshold usage level are able to opt-out of new program or the full portfolio of programs if they indicate that they have invested in energy efficiency at the site.

According to the Wisconsin Act 141, large energy customers have the opportunity to implement a self-directed energy efficiency program. This Wisconsin approach is similar to that taken in Michigan. More specifically, a large energy using customer of an energy utility may administer and fund its own energy efficiency programs. A customer that funds such a program may deduct the amount of the funding from the amount the energy utility may otherwise collect from the customer. In addition if the customer deducts the amount of the funding from the amount the energy utility may collect from the customer, the utility shall credit the amount of the funding against the amount the energy utility is required to spend for energy efficiency projects.

The South Carolina Electric & Gas (SCE&G) Company recently filed in Dkt. 2009-261-E its plan for implementing utility sponsored energy efficiency and demand side management programs and for approval of a rider to recover costs associated with these programs. In the filing, SCE&G provided an opt-out provision for large commercial and industrial customers. In order to be eligible, the customer has to certify in writing that they have conducted an energy efficiency audit within the past three years and are implementing measures that are at least equivalent in energy and demand savings to those anticipated under the Company's DSM program for the applicable customer class.

MWV thanks the Commission for its consideration of these Comments.



Todd J. Griset, Counsel for
MeadWestvaco Corporation
Preti Flaherty Beliveau & Pachios
P.O. Box 1058, 45 Memorial Circle
Augusta, ME 04332-1058
Tel: (207) 623-5300
tgriset@preti.com

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Interrogatories and Production of Documents of MeadWestvaco Corporation was served via first-class mail, postage pre-paid, this 31st day of July, 2009 to:

C. M. Browder, Jr.
Sr. Assistant Attorney General
Office of the Attorney General
Division of Consumer Counsel
900 East Main St., 2nd Fl.
Richmond, VA 23219

Kendrick R. Riggs, Esq.
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 W Jefferson St.
Louisville, KY 40202-2828

Barry L. Thomas
Director, Regulatory Affairs
American Electric Power Co.
1051 East Cary St., Ste. 702
Richmond, VA 23219

Pamela J. Walker
Deputy General Counsel
Dominion Resources Services Inc.
Law Dept, PH-1
P.O. Box 26532
Richmond, VA 23261-6532

Document Control Center
Office of the Clerk - SCC
P.O. Box 2118
Richmond, VA 23218

State Corporation Commission
Office of the Clerk – SCC
1300 E. Main St., 1st Fl.
Richmond, VA 23219

Irene A. Kowalczyk
Director, Energy Policy & Supply
MeadWestvaco Corp.
299 Park Ave, 13th Fl.
New York, NY 10171

Louis R. Monacell, Esq.
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219-3095

Edward L. Petrini, Esq.
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219-3095

Mr. Robert A. Vanderhuy
801 Ridge Drive
McLean, VA 22101-1625

Chris S. King
Chief Strategy Officer
eMeter Corporation
2215 Bridgepoint Parkway, Suite 300
San Mateo, CA 94404

Jack Greenhalgh, President
New Era Energy
P.O. Box 121
Williamsburg, VA 23090

Caleb Jaffe
Southern Environmental Law Center
201 West Main Street, Suite 14
Charlottesville, VA 22902

Anthony J. Gambardella, Jr.
Woods Rogers
823 East Main Street, Suite 1200
Richmond, VA 23219

W. Todd Benson, Esq.
Piedmont Environmental Council
P.O. Box 460
Warrenton, VA 20188

Sarah Rispin
Southern Environmental Law Center
201 West Main Street, Suite 14
Charlottesville, VA 22902-5065


Cliona M. Robb, Esq.
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219

David Prezioso
Vice President
Ice Energy Coproration
1357 Linley Trace
Marietta, GA 30056

Meera Ahamed, Esq.
Washington Gas Light Company
101 Constitution Avenue, NW
Washington, DC 20080

Richard D. Gary, Esq.
Noelle C. Coates, Esq.
Hunton & Williams, LLP
Riverfront Plaza, East Tower
951 East Byrd Street
Richmond, VA 23219-4074

M. Renae Carter
Dominion Law Department
P.O. Box 26532
Richmond, VA 23261


Todd J. Grisét, Counsel for
MeadWestvaco Corporation
Preti Flaherty Beliveau & Pachios
P.O. Box 1058, 45 Memorial Circle
Augusta, ME 04332-1058
Tel: (207) 623-5300
tgrisét@preti.com



CHRISTIAN | BARTON, LLP
Attorneys At Law

Edward L. Petrini, Esq.
Phone: 804.697.4135
Fax: 804.697.6395
E-mail: epetrini@cblaw.com

July 31, 2009

BY ELECTRONIC DELIVERY

Mr. Joel H. Peck, Clerk
Document Control Center
State Corporation Commission
1300 East Main Street - 1st Floor
Richmond, VA 23219

Re: Commonwealth of Virginia, At the relation of the State Corporation Commission, 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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly
Case No. PUE-2009-00023

Dear Mr. Peck:

Attached for filing in the above matter are the *Joint Comments and Supporting Brief of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates*.

The Commission's acknowledgment of this filing should be e-mailed to me at epetrini@cblaw.com.

If you have any questions regarding this filing, please contact me at (804) 697-4135.
Thank you for your assistance.

Very truly yours,

Edward L. Petrini

Enclosure

cc Certificate of Service

#971137

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA

At the relation of the

STATE CORPORATION COMMISSION

CASE NO. PUE-2009-00023

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

JOINT COMMENTS AND SUPPORTING BRIEF
OF THE
VIRGINIA COMMITTEE FOR FAIR UTILITY RATES
AND THE
OLD DOMINION COMMITTEE FOR FAIR UTILITY RATES

In accordance with the April 30, 2009 *Order Establishing Proceeding and Setting Evidentiary Hearing* ("Order"), the Virginia Committee For Fair Utility Rates ("Virginia Committee") and the Old Dominion Committee for Fair Utility Rates ("Old Dominion Committee") (collectively, "Committees"), by counsel, hereby file their joint comments and supporting brief ("Joint Comments") in this proceeding.

The members of the Virginia Committee are large industrial customers of Virginia Electric and Power Company ("Virginia Power"). The members of the Old Dominion Committee are large industrial customers of Appalachian Power Company.

I. INTRODUCTION

During the 2009 Session, the General Assembly enacted Chapters 752 and 855 of the 2009 Acts of Assembly. These identical measures ("Act"), which took effect on July 1, 2009, require the State Corporation Commission ("Commission") to conduct a formal public proceeding to determine 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 electric utility in the Commonwealth.

The Act further requires the Commission to report its findings to the General Assembly on or before November 15, 2009. The report must:

- (i) indicate the range of consumption and peak load reductions that are potentially achievable by each such utility, the range of costs that consumers would pay to achieve such reductions, and the range of financial benefits or savings that could be realized if the targets were met over a 15-year period; and
- (ii) determine a "just and reasonable ratemaking methodology" to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand-side management programs.

The Commission's evaluation must include an examination of the class cost responsibility methods used in other jurisdictions and an examination of other jurisdictions that permit certain nonresidential customers or classes of customers either to be exempt from paying for the utility demand-side management programs or to opt out of participating in or paying for such programs, and the Commission must determine whether it would be in the public interest for the Commonwealth to have a similar policy.

On April 30, 2009, the Commission issued its Order, which, *inter alia*, asks a series of questions relating to the issues raised by the Act and sets a schedule for implementing it. Subsequently, notices of participation were filed by the Committees,

eMeter Corporation; Mr. Robert Vanderhye; New Era Energy, Inc.; MeadWestvaco Corporation; Southern Environmental Law Center; Piedmont Environmental Council; ICE Energy Corporation; the Virginia Energy Purchasing Governmental Association; and Washington Gas Light Company. On June 30, 2009, three "generating electric utilities" filed direct testimony.¹

The Committees respectfully submit that it is in the "public interest" to permit certain customer classes to be exempt from or to opt out of paying for utility energy efficiency programs, and that Virginia law specifically so provides. During the same Session in which the General Assembly enacted the Act, the General Assembly also amended Va. Code § 56-585.1 A 5 c, which allows certain customers with a history of demand in excess of 500 kW to opt out and provides that no costs for such programs may be assigned to any customer having a verifiable history of demand of more than 10 MW.²

¹ Virginia Electric and Power filed its Direct Testimony ("Virginia Power's Testimony"), Appalachian Power Company filed its Comments and Testimony ("AEP's Testimony"), and Kentucky Utilities d/b/a Old Dominion Power Company filed its testimony.

² Va. Code § 56-585.1 A 5 c states, in pertinent part:

None of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, shall be assigned to any customer that has a verifiable history of having used more than 10 megawatts of demand from a single meter of delivery. Nor shall any of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, be incurred by any large general service customer as defined herein that has notified the utility of non-participation in such energy efficiency program or programs. A large general service customer is a customer that has a verifiable history of having used more than 500 kilowatts of demand from a single meter of delivery. Non-participation in energy efficiency programs shall be allowed by the Commission if the large general service customer has, at the customer's own expense, implemented energy efficiency programs that have produced or will produce measured and verified results consistent with industry standards and other regulatory criteria stated in this section. The Commission shall, no later than November 15, 2009, promulgate rules and regulations to accommodate the process under which such large general service customers shall file notice for such an exemption and (i) establish the administrative procedures by which eligible customers will notify the utility and (ii) define the standard criteria that must be satisfied by an applicant in order to notify the utility. In promulgating such rules and

This simultaneously enacted statute means that the General Assembly already has determined that, at minimum, it is in the public interest to permit certain customer classes to be exempt from, or to opt out of, paying for certain utility demand-side programs. Accordingly, whether the public interest is served by permitting customers and classes of customers to be exempt from or to opt out of paying for utility energy efficiency programs already has been answered in the affirmative for the customers and classes of customers specifically described in Va. Code § 56-585.1 A 5 c.³

The Committees nonetheless are interested in the outcome of this proceeding to the extent that their members may consume electricity that does not qualify for the exemption and, more importantly, to the extent that this proceeding may in some way affect the scope of the existing exemption or "opt out" provisions referenced above.

regulations, the Commission may also specify the timing as to when a utility shall accept and act on such notice, taking into consideration the utility's integrated resource planning process as well as its administration of energy efficiency programs that are approved for cost recovery by the Commission. The notice of non-participation by a large general service customer, to be given by March 1 of a given year, shall be for the duration of the service life of the customer's energy efficiency program. The Commission on its own motion may initiate steps necessary to verify such non-participants' achievement of energy efficiency if the Commission has a body of evidence that the non-participant has knowingly misrepresented its energy efficiency achievement. A utility shall not charge such large general service customer, as defined by the Commission, for the costs of installing energy efficiency equipment beyond what is required to provide electric service and meter such service on the customer's premises if the customer provides, at the customer's expense, equivalent energy efficiency equipment. In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection in the Commonwealth; ...

³ Virginia Power's Testimony concurs with the Committee. ("[T]he General Assembly passed House Bill 2506, which addressed class responsibility under Section 56-585.1 A 5 c." by allowing customers with over 500 kW of demand to opt out and by providing that no costs related to DSM programs may be assigned to any customer having a verifiable history of more than 10 MW." See, Virginia Power's Testimony at 21. Virginia Power's testimony concludes that "[g]iven that the General Assembly has enacted this language in the statute, the question regarding exempt an/or opt-out customers has already been defined." Id.)

Accordingly, in implementing the Act, the Commission should bear in mind the strong public interest considerations that support the need for shielding large industrial customers from participation in or paying for utility-sponsored energy efficiency programs. Indeed, the Act specifically requires implementation by the Commission with the public interest in mind. Specifically, in determining the tests to be given the greatest weight when preparing a cost-benefit analysis of a demand-side management program, the Commission must take into consideration “the public interest” and the potential impact on economic development in Virginia, and the Act requires that the Commission determine whether it would be in “the public interest” for Virginia to have policies similar to those in other states in which nonresidential customers or classes of customers are exempt from paying for such programs or may opt out of participating in or paying for them.

Large industrial customers do not face the same market barriers to energy efficiency investments that other classes of customers may face. Such customers are more likely to reflect the following characteristics:

- typically energy intensive, with energy comprising a significant cost of doing business
- often price sensitive
- knowledgeable about energy efficiency
- have previous experience with energy efficiency projects and already have undertaken projects to capture the low-hanging fruit, such as lighting and motor retrofits
- energy efficiency projects undertaken generally are facility, industry, and/or process specific, which make them the exact opposite of the “cookie cutter” type programs prevalent for smaller customers
- concerned about implementing projects subsidizing projects for less efficient customers, including some that may be business competitors⁴

⁴ See, *Financing Energy Efficiency Investments of Large Industrial Customers: What is the Role of Electric Utilities?*, published by the Electricity Consumers Resource Council, dated December 15, 2008 (“ELCON Efficiency Paper”), at 2, available at <http://www.elcon.org/Documents/Publications/PolicyBrief12-16-08.pdf>.

Large industrial customers typically can access capital markets and borrow funds at the same or lower rates than utilities.⁵ In Virginia, this may be more true now than previously, with the numerous rate “incentives” for electric utilities included in Va. Code § 56-585.1. Moreover, it is in the interest of such customers to deploy the most cost-effective energy efficiency measures in their facilities. Increases in the cost of energy affect their competitiveness, so investments to improve energy efficiency are essential if they are to compete in what increasingly has become a global marketplace. By using their own funds, large industrial customers do not need to share the bill savings attributed to energy efficiency improvements with the utility.

Regulatory policies that mandate such customers’ participation in utility energy efficiency programs, however, may result in *less* energy efficiency improvements or in improvements that cost more than necessary. Utility energy efficiency programs may not be designed to meet the specific needs of a large industrial facility, where energy efficiency improvements are intertwined with a complex industrial process and the facility’s often unique characteristics. Inflexible utility mandates, moreover, can turn out to be more costly than other means that a customer could initiate on its own. Indeed, mandatory, utility-sponsored energy efficiency programs may create perverse incentives for customers to become free riders.⁶ Such programs may cause industrial customers to shift from self-directed investments, using their own resources, to becoming free riders on utility programs, with less cost-effective measures (at higher capital costs) as a result.

⁵ Id. See the ELCON Efficiency Paper, *supra*, for characteristics of large industrial electricity customers, their usage, and their special circumstances.

⁶ Id.

Accordingly, the Commission should recommend no changes in the current exemption and "opt out" provisions contained in Va. Code § 56-585.1 A 5 c, and it should bear in mind the implications for large industrial customers not covered by those provisions in implementing the Act in the instant case.

II. RESPONSES TO QUESTIONS IN COMMISSION ORDER

The Committees respond to certain of the questions set forth in the Order as follows:

- 1. What is an achievable, cost-effective energy conservation and demand response target that can be realistically achieved through the generating electric utility's demand-side management portfolio?**

The Committees do not advocate adoption of a specific target; however, the Commission should take into account certain factors, discussed below, in setting such a target.

First, the Commission should recognize that utilities often are not the primary delivery agents of energy efficiency, and that, in fact, non-utility methods and means for delivering energy efficiency can and do offer significant opportunities. These include building codes; tax credits; governmental programs, such as the U.S. Department of Energy's "Energy Star" program; research and development ("R&D") via the national labs or industry-sponsored entities, such as the Electric Power Research Institute ("EPRI"), or R&D via manufacturers of lighting, appliances, and heating, ventilating, and cooling ("HVAC") equipment; sales incentives by retailers, and third party providers. In particular, with respect to the last -- opportunities related to the third party providers -- it should be emphasized that outsourcing the design, administration, and implementation of utility-funded energy-efficiency and demand side management initiatives could increase

their benefits. An outside party may have greater expertise, more experience, and more robust financial incentives than a utility in maximizing the benefits of energy efficiency.

Second, although it may not be possible at this time to estimate with certainty the level of contribution toward efficiency goals that can be achieved through means other than utility energy efficiency programs, it should be recognized that non-utility programs could well play a larger, better role than programs funded by captive utility ratepayers.

Third, an energy conservation and demand response target can hardly be considered to be "cost effective" if other, considerably more "cost-effective" means for the delivery of energy efficiency exist outside of utility-sponsored DSM programs. Accordingly, to the extent a specific overall energy conservation and demand response goal is deemed desirable, an argument can be made that the Commission should take into account funding mechanisms not funded by captive utility customers to lower the goal otherwise attributable to utility customer-funded programs. Thus, for example, as AEP's Testimony indicates, taking into account only known, enacted building and equipment codes and standards and changes in such standards change over time will "limit the overall potential in the future for utility-based programs."⁷

Fourth, in determining "cost effective," "achievable" goals, the Commission should exercise caution. If such targets are used to fashion electric utilities' demand-side portfolios, utility customers likely will be asked to fund them. For that reason alone, the Commission should exercise caution in approving financial commitments to be borne by customers. The impact on consumers, large and small, of the current economic downturn only underlines the importance of this consideration. Utility-sponsored energy conservation portfolios, accordingly, should be determined to be "cost effective" and

⁷ AEP's Testimony, Direct Testimony of Fred D. Nichols, II at 5.

used only after other, less-costly means of achieving consumption reductions have been evaluated comprehensively. Enhanced standards and codes may have a larger reach and impact than any single efficiency program and, possibly, all efficiency programs combined.

Fifth, the Commission should not ignore the fact that costs related to codes and ordinances would be borne by the beneficiaries. This contrasts with electric utility ratepayer-funded programs in which non-participants may be asked to shoulder a portion of the costs.

Sixth, as discussed above, the General Assembly has spoken with respect to certain large industrial customers, so the Commission should not take such customers into account when determining cost effective, achievable targets for utility-sponsored energy efficiency programs. Because of the public policy problems associated with application of such utility-sponsored programs to industrial customers, moreover, the Commission should determine that their participation should be limited, as more fully discussed in the Introduction to these Joint Comments.

In sum, while the Committees do not recommend particular targets, they do recommend that the Commission take into account the above factors in setting such targets.

- 2. What industry-recognized tests should be used in determining cost-effective consumption and peak load reductions and what relative weighting should be afforded to any test recommended for use by the respondent generating electric utility?**

The Commission addressed the appropriate tests in its June 28, 1993 *Order on Cost/Benefit Measures* in PUE-1990-00070,⁸ which found that DSM programs are to be analyzed from a multi-perspective approach using four tests: the Participants Test, the Utility Cost Test, the Ratepayer Impact Test, and the Total Resource Cost Test. The Staff Report issued in that proceeding found that a fifth test, the Societal Cost Test, was also used in some jurisdictions; however, the Commission determined that it did not have the statutory authority to consider the externalities that this test considered: effects on health, safety, local economy, and the environment.

If the Commission elects to consider the Societal Cost test, it should be given relatively little weight. Captive ratepayers should pay for electric service, including the environmental costs incurred by their electric utility in order to provide such service (*e.g.*, costs incurred to meet requirements for scrubbers or to pay carbon taxes). Comparing “society’s” costs with resource savings and non-cash costs and benefits (including benefits related to “the environment, health, safety, and local economic effects”⁹) requires, at best, application of a vague and potentially complex, difficult standard.

The Ratepayer Impact Test should be the primary test because, again, adoption of energy efficiency programs could entail substantial expenditures ultimately borne by captive ratepayers, and that requires a conservative approach. For the same reason, any such programs should be evaluated on an individual, rather than on a total portfolio, basis.

⁸ *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In Re: Investigation of conservation and load management programs*, SCC Case No. PUE-2000-00070, Order Issuing Rules on Cost/Benefit Measures, dated June 28, 1993, 1993 SCC Ann. Rpt. 242, 243.

⁹ *Id.*

3. How should the Commission define the terms “achievable,” “cost-effective,” and “be realistically accomplished” as they are used in the statute cited above?

A. Measure vs. program vs. portfolio basis

“Cost effective” could be determined on the basis of (1) each separate measure used in a program, (2) the program as a whole (so less cost-effective measures could be used as long as they are balanced within the program by more cost-effective measures), or (3) a portfolio basis, so that programs that are not cost-effective still could be adopted as long as they are balanced by programs that are cost effective. Consistent with the need to conserve ratepayer resources and exercise caution in determining goals for utility-sponsored energy efficiency targets, the Commission should determine “cost effective” on the basis of each separate measure used in a program.

B. Achievable potential

Virginia Power’s Testimony describes three categories that could be used to assist in determining the range of achievable potential for energy efficiency and demand response: technical potential, economic potential, and achievable potential.

Technological potential is the broadest term because it represents savings that would occur if all customers “adopted the most efficient, commercially available technologies and measures, *regardless of cost.*”¹⁰ Economic potential is more narrow because it represents savings that would occur if all customers “adopted the most efficient, commercially available *cost-effective* technologies.”¹¹ Achievable potential is the most narrow because it takes into account barriers to customer adoption and likely customer

¹⁰ Virginia Power’s Testimony at 11.

¹¹ Id. at 12.

behavior.¹² The Commission should emphasize achievable potential when evaluating energy efficiency programs.

C. “Cost effective” relative to non-utility programs

As discussed above, energy conservation and demand response targets can hardly be considered to be “cost effective” if other, more “cost-effective” means for delivery of energy efficiency exists outside of utility-sponsored programs. Moreover, the prospect of adding to the electricity rate burdens now faced by utility customers argues for a cautious approach to the determination of “cost effective” goals.

4. How should the Commission determine the “public interest” in preparing a “cost benefit analysis of a demand-side management program”?

The Commission’s determination of “the public interest” in implementing the Act, including its preparation of a “cost benefit analysis of a demand side management program,” is addressed in the Introduction to these Joint Comments (above).

5. What is the potential impact of a utility’s demand-side management program on economic development in the Commonwealth?

The Introduction to these Joint Comments discusses the strong public interest considerations that support the need for shielding large industrial customers from participation in or paying for utility-sponsored energy efficiency programs. Such considerations suggest that a utility’s demand-side management program could impede economic development in the Commonwealth to the extent that such customers are not shielded from such participation.

6. What is the “range of consumption and peak load reductions that are potentially achievable by each generating electric utility”?

¹² Id. .

As indicated above, the Committees do not advocate a specific reduction, but they urge the Commission to adopt a cautious approach to such determination due to the potential impact on customer rates of such a determination.

7. **What is the “range of costs that consumers would pay to achieve those reductions and the range of financial benefit or savings that could be realized if the targets were met over a 15 year period”?**

Because the Committees do not advocate targets for specific consumption and peak load reductions, they do not estimate a range of financial benefit or savings that could be realized if such targets were realized.

8. **How should the Commission “determine a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand side management programs”?**

- A. **Cost allocation and cost recovery should be implemented in a manner consistent with cost causation principles.**

The Commission should assign cost responsibility for each efficiency program to customer classes and rate schedules based on program eligibility and receipt of direct program benefits. This means that costs for residential programs should be recovered from residential customers, the costs for smaller non-residential customers' programs should be recovered from such customers, etc.

- B. **Cost of service principles should apply to mechanisms used to collect costs.**

After cost responsibility is calculated, the costs should be recovered within each class, or customer-type, in a manner reflective of cost of service principles. For instance, to the extent efficiency programs reduce both energy consumption and peak demands, the cost of such programs should be recovered partly on the basis of energy and partly on the basis of demand. Of course, this does not matter for non-demand metered customers,

such as residential customers, but it does make a difference to larger non-residential customers. It is important that the Commission not adopt a simplistic cost recovery methodology, like merely imposing an across-the-board volumetric surcharge. Instead, the Commission should evaluate more sophisticated cost-based approaches, based on the number of accounts, demand and/or consumption. Such approaches would best promote intraclass equity.

9. **What “class cost responsibility methods [are] used in other jurisdictions,” and “would [it] be in the public interest for the Commission to have a similar policy” to other jurisdictions that permit certain customers to be exempt from participating in and/or paying for a utility’s demand-side management programs”?**

As discussed in the Introduction to these Joint Comments, it is in the “public interest” to permit certain customer classes to be exempt from or to opt out of paying for utility demand-side management programs, and Virginia law specifically so provides. Further, in implementing the Act, the Commission should bear in mind the strong public interest considerations that support the need for shielding large industrial customers from participation in or paying for utility-sponsored energy efficiency programs. As discussed above, a utility’s demand-side management program could impede energy efficiency and economic development in the Commonwealth if large industrial customers are not shielded from participation in such programs and from paying for their costs.

III. CONCLUSION

The Committees recommend that the Commission implement the Act in accordance with the recommendations discussed above.

Respectfully submitted,

VIRGINIA COMMITTEE FOR FAIR
UTILITY RATES
OLD DOMINION COMMITTEE FOR
FAIR UTILITY RATES

By Counsel



Louis R. Monacell, Esq.
Edward L. Petrini, Esq.
Christian & Barton, LLP
909 E. Main Street, Ste. 1200
Richmond, Virginia 23219
Phone: (804) 697-4100
Fax: (804) 697-4122
lmonacell@cblaw.com
epetrini@cblaw.com

July 31, 2009

CERTIFICATE OF SERVICE

I certify that on this 31st day of July, 2009, a copy of the foregoing was hand-delivered or mailed, first-class, postage pre-paid, to the parties listed below.



Edward L. Petrini

Don R. Mueller
Associate General Counsel
State Corporation Commission
1300 East Main Street, 10th Floor
Richmond, VA 23219

Patrick R. Scanlon, Esq.
Todd J. Griset, Esq.
Donald J. Sipe, Esq.
Preti, Flaherty, Beliveau & Pachios
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332

C. Meade Browder, Jr., Esq.
Office of the Attorney General
Division of Consumer Counsel
900 East Main Street, 2nd Floor
Richmond, VA 23219

Irene A. Kowalczyk, Director
Energy Policy & Supply
MeadWestvaco Corporation
299 Park Avenue, 13th Floor
New York, NY 10171

Kendrick R. Riggs, Esq.
Stoll Keenon, Ogden
2000 PNC Plaza
500 West Jefferson Street
Louisville, KY 40202-2828

Mr. Robert A. Vanderhye
801 Ridge Drive
McLean, VA 22101-1625

Chris S. King
Chief Strategy Officer
eMeter Corporation
2215 Bridgepointe Parkway, Suite 300
San Mateo, CA 94404

Jack Greenhalgh, President
New Era Energy
P.O. Box 121
Williamsburg, VA 23090

Caleb Jaffe, Esq.
Sarah Rispin, Esq.
Southern Environmental Law Center
201 West Main Street, Suite 14
Charlottesville, VA 22902

Anthony J. Gambardella, Jr., Esq.
Woods Rogers
823 East Main Street, Suite 1200
Richmond, VA 23219

Richard D. Gary, Esq.
Noelle C. Coates, Esq.
Hunton & Williams LLP
Riverfront Plaza, East Tower
951 East Byrd Street
Richmond, VA 23219-4074

David Prezioso, Vice President
Ice Energy Corporation
1357 Linley Trace
Marietta, GA 3056

Meera Ahamed, Esq.
Washington Gas Light Company
101 Constitution Avenue, NW
Washington, DC 20080

W. Todd Benson, Esq.
Piedmont Environmental Council
P.O. Box 460
Warrenton, VA 20188

Pamela J. Walker, Esq.
M. Renae Carter, Esq.
Dominion Virginia Power
P.O. Box 26666
Richmond, Virginia 23261

#967139



101 Constitution Avenue, NW
Washington, DC 20080
www.washingtongas.com

Direct Dial (202) 624-6622
Facsimile (202) 624-6012
mahamed@washgas.com

July 31, 2009

BY ELECTRONIC FILING

Mr. Joel H. Peck, Clerk
Virginia State Corporation Commission
Document Control Center
Tyler Building, 1st Floor
1300 East Main Street
Richmond, Virginia 23219

Re: Ex Parte: In the matter of the 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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly, Case No. PUE-2009-00023

Dear Mr. Peck:

In accordance with Ordering Paragraph (7) of the State Corporation Commission's April 30, 2009 Order Establishing Proceeding and Setting Evidentiary Hearing in this proceeding, attached for filing are the Comments of Washington Gas Light Company.

Thank you for your assistance in this matter.

Sincerely yours,

A handwritten signature in black ink that reads "Meera Ahamed".

Meera Ahamed, Esquire
Office of General Counsel

Enclosures

cc: Don Muller, Esquire, Office of General Counsel, State Corporation Commission

BEFORE THE STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA,

At the relation of

STATE CORPORATION COMMISSION

CASE NO. PUE-2009-00023

Ex. Parte: In the matter of determining achievable, cost-effective energy conservation and demand response targets that can be realistically be accomplished in the Commonwealth through demand-side management portfolios administered by each generating electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly

COMMENTS OF WASHINGTON GAS

On April 30, 2009 the State Corporation Commission (“Commission”) issued an Order Establishing Proceeding and Setting Evidentiary Hearing in Case No. PUE-2009-00023 (“Order”). The Commission established the proceeding in response to directives included in Chapters 752 and 855 of the 2009 Acts of Assembly enacted in the 2009 Session of the Virginia General Assembly.¹ The legislation requires the Commission to report its findings regarding 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 electric utility in the Commonwealth. An evidentiary hearing is scheduled for September 23, 2009. Pursuant to Ordering Paragraph (7) of the Commission’s Order, interested parties may file comments in this proceeding by July 31, 2009. These are Washington Gas Light

¹ Chapters 855 (senate bill 1348) and chapter 752 (House Bill 2531) of the 2009 Acts of Assembly became effective on July 1, 2009.

Company's ("Washington Gas" or "Company") comments to some of the questions posed by the Commission in its Order.

BACKGROUND

The Virginia Energy Plan 2007 ("the Plan") was developed in accordance with legislation enacted in 2006, and updated with legislation enacted in 2007. The Plan develops a 10-year state energy plan, to be first updated in 2010 and then every four years thereafter. The Plan requires actions to be taken by individuals, businesses and government to increase energy-efficiency and conservation actions, provides for a diverse portfolio of energy supplies including traditional and alternate energy sources, provides the needed infrastructure to deliver conservation services and energy supplies, and provides for focused research, development and the deployment of new energy technologies.

In 2008, the General Assembly passed into law Senate Bill 718 which mandates that investor-owned electric utilities report annually on their efforts to conserve energy. The measure also requires electric utilities to report annually on how they will meet the renewable portfolio standard goals, and provide for renewable generation, and relevant advances in renewable energy generation technology.

With the development of utility conservation programs, the Plan shows that Virginia should be able to cost effectively achieve a 14 percent reduction in electric energy use. The General Assembly established a goal that 10 percent of electric use by retail customers (using 2006 as the base year) should be offset by conservation and efficiency by the year 2022. The General Assembly directed the Commission to determine if the 10 percent goal can be cost effectively achieved, to identify the mix of

programs to be used to achieve the goal, and to develop an implementation plan that both identifies the entities that could most effectively implement the programs and that also estimates the cost of attaining the goal. The developed programs are to be tested for cost effectiveness using tests such as the Total Resource Cost Test, the Societal Test, the Program Administrator Test, the Participant Test, and the Rate Impact Test.

Washington Gas previously provided comments in response to the Commission's Order Proposing Guidelines and Directing the Filing of Integrated Resource Plans in Case No. PUE-2008-00099.² Washington Gas asserts that dramatic reductions in electricity usage can be obtained from promoting more efficient, direct use of natural gas for residential and commercial heating. Washington Gas supports fuel switching programs that would produce electricity savings associated with the conversion of an electric home to natural gas heating.

In the comments herein, Washington Gas specifically addresses the reduction of electric load and consumption while reducing green house emissions, and simultaneously improving the efficiency with which energy is consumed. In general, Washington Gas encourages the use of natural gas where it is a viable substitute for electricity and converting loads currently served by electricity to natural gas in order for Virginia electric utilities to realize their energy reduction goals (see Washington Gas response to question number (6) below).

² *Commonwealth of Virginia, ex. rel, State Corporation Commission, Concerning Electric Utility Integrated Resource Planning Pursuant to Sections 56-597 et seq of the Code of Virginia, Order Proposing guidelines and Directing the Filing of Integrated Resource Plans* , issued November 12, 2008.

COMMENTS

Washington Gas offers its comments for the Commission's consideration as the Commission deliberates on achieving cost-effective energy conservation and demand response targets that can realistically be achieved through demand side management portfolios. Washington Gas offers several innovative ways to achieve electric peak load reductions. The Company makes the following specific comments related to the Commission's questions 1, 2, 5 and 6 in the Order. The Company does not have any comments on questions 3 and 4.

Question 1: What is an achievable, cost-effective energy conservation and demand response target that can be realistically accomplished through the generating electric utility's demand-side management portfolio?

Response: Conservation targets can be set more aggressively, and could be met more cost-effectively, if the solutions are not based on a single-fuel vision. The energy portfolio for the Commonwealth comprises more than just electricity, and the portfolio of the total energy cycle consists of more than just one fuel. If the Commission encouraged the use of the most efficient energy source for each end use, rather than just improving the efficiency of the fuel being used, more aggressive energy conservation and demand response targets could be set, or at the very least, set targets could be more easily achieved. By establishing policies and programs that encourage changing a less efficient energy source to a more efficient energy source, the Commission would be maximizing the success of these efforts and capitalizing on the idea of energy efficiency. In the past, several Commissions have rejected this approach assuming they would be interfering with the competitive market. However, where customers do not have complete information about the costs of a program, the Commission can help fill that gap.

Question 2: What industry- recognized tests should be used in determining cost-effective consumption and peak-load reductions and what relative weighing should be afforded to any test recommended for use by the respondent generating electric utility?

Response: As defined in Va. Code Section 56-600 of the 2008 Conservation and Ratemaking Efficiency Act, cost effectiveness is determined by analyzing conservation and energy efficiency programs, using “the Total Resource Cost Test, the Societal Test, the Program Administrator Test, the Participant Test, the Ratepayer Impact Measure Test, and any other test the Commission deems reasonably appropriate.”

The most recent industry standards manual referred to as the California Standard Practice Manual describes the tests as follows:

- The Total Resource Cost Test- This test is designed to measure whether the demand side measure is cost-effective from society’s standpoint. Since this test can be derived as the sum of the Participant Test and the Ratepayer Impact Measure Test, it is often referred to as the All Ratepayers Test.
- The Societal Test- A variant of the Total Resource Cost Test is the Societal Test, which modifies the TRC in the following ways: uses higher marginal costs to reflect the cost to society of the more expensive alternative resources and to reflect externality costs not captured by the market system, omits tax credits and capital costs in the year in which they occur and uses a societal discount rate.
- The Program Administrator Cost Test- This test is designed to measure the cost-effectiveness of a demand side measure as a utility resource alternative.
- The Participant Test- This test determines whether the demand side measure is cost effective for the party who receives the demand side treatment.
- The Ratepayer Impact Measure Test- This test determines the impact that the demand side measure will have on non-participants. Because of this, the test is often referred to as the Non-Participants Test, and measures the rate impacts of the utility offering the program.

The Total Resource Cost (“TRC”) Test is generally regarded as the controlling test of any demand side measure because it attempts to measure the societal cost

consequences of the measure and is therefore a broad determination of cost-effectiveness. The TRC test is sometimes referred to as the All-Ratepayers Test (“ART”) because it is a mathematical combination of the Participant Test and the Ratepayer Impact Measure (“RIM”) Test; that is, it measures the impact on all ratepayers. This test compares all benefits from a demand side measure to all costs of the program. Thus, implementation of a demand side measure will result in benefits to society as a result of costs avoided by the affected utilities, tax credit benefits to participants and costs avoided by participants. These benefits will be offset by costs incurred by utilities, costs incurred by participants, and any costs associated with increased load.

Virginia Code Section 56-600 defines a cost-effective conservation and energy efficiency program as one that is designed to decrease the average customer’s annual, weather-normalized consumption or total gas bill, for gas and non-gas elements combined, or avoid energy costs or consumption the customer may otherwise have incurred. A program must be cost-effective based on the benefit/cost test results.

Question 5: What is the potential impact of the generating electric utility’s demand-side management program on economic development in the Commonwealth?

Response: Certainly, it is not difficult to make the connection that by lowering the cost of electricity, either from the perspective of the upfront appliance investment or the ongoing operating costs, economic development can occur more easily. However, by implementing a single-fuel focus, the competitive “playing field” for all energy sources will skew the market. This could result in exactly the wrong decision being made if energy efficiency is the goal. Natural gas is more efficient than electricity for important energy consuming appliances. However, if natural gas is not an option for the customer to choose, or if the cost of electricity is so artificially low that it becomes the more

attractive option, economic development happens, but it happens at the expense of energy efficiency. The economic development that will occur could actually result in the Commonwealth not meeting its targets as a less efficient energy supply could have been chosen.

Question 6: What is the “range of consumption and peak load reductions that are potentially achievable by each generating electric utility”?

Response: A comprehensive analysis of all existing and new resource options (supply- and demand-side) should be considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, preferably at least cost, over the planning period.

- a. Demand-side Options - assess programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.
- b. Evaluation of Resource Options - analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs, system operations, and other qualitative factors.

Such thorough analysis would necessarily include the evaluation of programs that encourage the conversion of electric appliances to natural gas appliances where that is the best economic option. These programs could arguably be the most important resources for reducing electricity consumption and green house emissions, while simultaneously improving the efficiency with which energy is consumed in the Commonwealth. In fact, comprehensive energy efficiency programs that consider multiple fuels can accomplish

the same goal more efficiently and with less green house emissions than any generation resource.

The factual basis for this position is as follows:

1. Encouraging the use of natural gas where it is a viable substitute for electricity and converting loads currently served by electricity to natural gas will improve the efficiency with which energy is consumed in the state. Generally, natural gas retains roughly 90% of its energy value throughout the process required to extract, process and deliver gas to the consumer whereas electricity retains less than 30% of its energy through this "source-to-site" cycle.³ As a result, natural gas utilized in a direct space heating or water heating application is significantly more efficient on a "total fuel cycle" basis, including both source-to-site and appliance efficiency, than the use of electricity for the same purposes, especially in relation to water heating, where a comparison of efficiency levels of electric and natural gas appliances can reasonably be made. Specifically, a comparison of electric efficiency from delivered electric power to the efficiency from the direct use of natural gas in a residence, illustrates that the total energy used to operate a single electric water heater could run 2.3 natural gas water heaters.⁴
2. Encouraging the use of natural gas where it is a viable substitute for electricity and converting loads currently served by electricity to natural gas will reduce electricity usage and could become an important component of an overall energy efficiency strategy for the state. Using publicly available state energy consumption data, it is easy to demonstrate that natural gas acts as a substitute for electricity (as natural gas is substituted for electricity, electricity consumption declines). For example, 2004 state energy consumption data compiled by the Energy Information Administration show a statistically significant negative relationship between the percentage of energy at the state level that is supplied by electricity and the percentage of electricity that is provided by natural gas.⁵ Thus, electricity savings will be achieved by natural gas fuel switching strategies.
3. Encouraging the use of natural gas where it is a viable substitute for electricity and converting loads currently served by electricity to natural gas will reduce CO₂ emissions and could become an important component of an overall energy efficiency strategy for the state. Based on "Model Energy Code Standards," an electric home emits 13.3 tons of CO₂ while a comparable gas home emits 9.5 tons of CO₂. In other words, a natural gas home emits 30% less CO₂. Given the

³ An August 2000 White paper issued by the American Gas Association entitled "Source Energy and Emission Factors for Residential Energy Consumption," which incorporated data gathered from the Environmental Protection Agency, the Energy Information Agency, and the Gas Research Institute, among others, reported that the relative cumulative efficiency of natural gas versus electricity on an extraction through distribution basis revealed that natural gas was 90.5% efficient when delivered to a site for combustion whereas electricity was between 25.7% and 26.9% efficient when distributed for end use.

⁴ *Id.*

⁵ U.S. DOE/EIA, 2004 Annual Energy Outlook, 2004, Table A.4.

efficiency benefits cited above and the relatively lower level of emissions by direct burning of natural gas in the home, it is clear that a significant portion of the Legislature's electricity savings goals could be achieved through natural gas fuel switching and could be achieved with significantly less CO₂ and other pollutant emissions.

Furthermore, cost-effective fuel switching could result in reduced rates for both gas and electric customers. What this means is that it is vital that the Commission establish policies to encourage the most efficient fuel at the end use level.

Based on the foregoing, Washington Gas recommends the following policies :

1. Conservation and energy efficiency programs for application in competitive markets should be analyzed on a multi-fuel and comprehensive basis, looking at all reasonably available competing energy products and services and taking into consideration all likely impacts of the proposed programs (including impacts on load growth).
2. Conservation and energy efficiency programs should be analyzed on a full fuel cycle (source-to-site plus appliance efficiency) basis.
3. Conservation and energy efficiency programs and utility rates should be constructed in a manner designed to create incentives for consumers to use energy wisely and remove disincentives for utilities to promote conservation.
4. Conservation and energy efficiency programs should promote the use, among feasible alternatives, of the most efficient and lowest emitting energy sources in particular applications.
5. Any electric-only demand side management ("DSM") proposal should be required to demonstrate that any programs submitted for Commission approval will be implemented in a fuel-neutral manner, should monitor for fuel switching caused by the programs or, if these programs do result in fuel-switching, that fuel-switching serves the overall public interest.
6. Electric DSM programs should be approved only after it has been demonstrated that the offering entity has considered and evaluated all potential programs, including perhaps the most important resource for reducing electricity consumption and CO₂ emissions, while simultaneously improving the efficiency with which energy is consumed: encouraging the usage of natural gas where it is a viable substitute for electricity and converting loads currently served by electricity to natural gas.

CONCLUSION

The Commonwealth of Virginia is seeking a reduction in electric use, and has the unique opportunity to lead a discussion on the benefits from the direct use of natural gas for fuel efficiency. Dramatic reductions in electricity usage can be obtained from a promotion of more efficient direct use of natural gas for residential and commercial heating. Specifically, Washington Gas supports fuel switching programs that would address electricity savings associated with the conversion of an electric home to natural gas heating. An innovative fuel switching pilot program would address electricity savings and demand reduction targets by facilitating the direct use of natural gas through the conversion of homes which currently use electricity for heating and hot water. Such a program would, in Washington Gas's opinion, result in positive impacts for both electric and natural gas users in Virginia, by lowering costs for electricity and encouraging energy efficiency.

As the Commission continues to make the important decisions that will impact the lives of millions of Virginians for decades to come, Washington Gas believes that the Commission should implement novel solutions to the electric load problems, and not simply rely on the past generation of efficiency programs. To that end, Washington Gas respectfully makes the following recommendations:

1. The Commission should direct electric utilities to design programs that achieve the maximum electricity savings. Fuel switching is compatible with the Virginia Energy Plan and legislation direction provided by the General Assembly. Fuel switching programs should not be ignored as part of the electric utility filings and are far more cost-effective than any programs that can be designed alone. Furthermore, fuel-switching programs will result in downward pressure on rates for both gas and electric customers in Virginia. Washington Gas will be happy to work cooperatively with the electric utilities to achieve these goals.

2. The Commission should carefully evaluate programs that could increase electricity usage at the expense of natural gas. Inefficient use of natural gas through electric generation can be avoided through well-designed efficiency programs.

July 31, 2009



CHRISTIAN | BARTON, LLP
Attorneys At Law

CLIONA MARY ROBB
Tel: (804) 697-4140
Fax: (804) 697-6140
E-mail: crobb@cblaw.com

July 31, 2009

ELECTRONICALLY FILED

Mr. Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, 1st Floor
Richmond, VA 23219

**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
Case No. PUE-2009-00023**

Dear Mr. Peck:

Enclosed for filing are the *Comments/Supporting Brief of the Virginia Energy Purchasing Governmental Association* in the above matter.

Thank you for your assistance.

Sincerely,


Cliona Mary Robb

CMR/nh
Enclosure

970507

cc: Service List

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

At the relation of the

STATE CORPORATION COMMISSION

CASE NO. PUE-2009-00023

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

**COMMENTS/SUPPORTING BRIEF
OF THE
VIRGINIA ENERGY PURCHASING GOVERNMENTAL ASSOCIATION**

In accordance with the April 30, 2009 *Order Establishing Proceeding and Setting Evidentiary Hearing* (Order), the Virginia Energy Purchasing Governmental Association (VEPGA) hereby files its comments/supporting brief in this proceeding.

I. INTRODUCTION

A. VEPGA Members are Non-Jurisdictional Customers

The Virginia Energy Purchasing Governmental Association, or VEPGA, is an association of over 180 local jurisdictions (counties, cities and towns) and political subdivisions (boards and authorities) across the Commonwealth of Virginia that receive electric service from Virginia Electric and Power Company (Virginia Power).¹

For decades, VEPGA and its predecessor have taken advantage of the opportunity provided under Virginia law for local governments and other political subdivisions of the

¹ VEPGA is the successor to the VML/VACO Virginia Power Steering Committee. A list of VEPGA members as of November 2008 is available at www.vepga.org/pages/members.htm.

Commonwealth collectively to negotiate their rates, terms, and conditions of electric service from Virginia Power. As a result, VEPGA's negotiated rate schedules and its terms and conditions typically differ from those that apply to Virginia Power's jurisdictional customers. For example, the VEPGA fuel factor does not include statutorily-required deferrals because VEPGA never agreed to freeze the fuel factor applicable to its members. Additionally, various riders affecting jurisdictional rates do not affect VEPGA's current rates because VEPGA negotiated a base rate freeze through December 31, 2010.

There have been instances when VEPGA and Virginia Power have agreed, via contract, that VEPGA would be treated similarly to jurisdictional customers. Consequently, the conservation and demand response model adopted for jurisdictional customers in this proceeding may influence VEPGA's future contract negotiations with Virginia Power.

VEPGA appreciates the opportunity afforded by the Commission's Order to comment on determining achievable, cost-effective energy conservation and demand response targets that can be realistically accomplished through demand side management ("DSM") portfolios administered by certain generating utilities.

B. VEPGA Members Voluntarily Implement Conservation and Demand Response Measures

Conservation, energy efficiency, and demand response are VEPGA priorities. Many VEPGA members voluntarily commit significant resources to implement energy efficiency and conservation measures. For example, **Exhibit A** describes measures undertaken by Fairfax County Government; **Exhibit B** describes measures undertaken by Fairfax County Public Schools; and **Exhibit C** describes measures undertaken by

Loudoun County Public Schools. Information regarding these and other energy efficiency and conservation measures are shared with VEPGA members via the association's website and periodic seminars.² Moreover, VEPGA has educated its members about PJM demand response opportunities and is committed to working with Virginia Power to identify and implement energy-saving opportunities. Most recently, negotiations between VEPGA and Virginia Power resulted in the initiation of a limited pilot program to evaluate the possible advantages and limitations of light emitting diode, or LED, streetlight fixtures. If successful, widespread implementation of LED streetlighting could achieve significant energy savings across the Commonwealth.

C. VEPGA's Recommended Guidelines and Principles

VEPGA supports state policies that encourage the implementation of cost-effective energy efficiency, demand response, and DSM measures that are consistent with the following guidelines and principles:

- Programs should primarily focus on energy efficiency measures that result in lower usage, especially during peak periods, and avoid some of the need for new generation and transmission infrastructure.
- Programs should accommodate all options that lead to the lowest projected long-term net cost instead of options that seek to guarantee earnings for utilities.
- Programs should be established on the basis of an accurate assessment of potential energy efficiency savings.

² Materials from VEPGA's 2008 Energy Seminar are available at www.vepga.org/pages/vepgapubs.htm. Also available are several energy-related presentations from VEPGA's 2009 Annual Meeting.

- Programs should provide for the periodic auditing of operations, costs, and claimed savings to ensure the programs operate efficiently and economically and meet the stated goals and objectives.
- As a general principle, an individual customer should be permitted to retain the economic benefit of its energy conservation efforts and be credited for expenditures related to the customer's own, self-funded efforts to reduce electricity usage.
- Municipal customers, whose rates are non-jurisdictional, should be subject to programs that are determined via their contracts with utilities, rather than determined via the programs applicable to jurisdictional customers.
- Rate impacts on customers should be minimized.

II. RESPONSES TO QUESTIONS IN SCC ORDER

In this section, VEPGA responds to Questions 8 and 9 as set forth in the SCC's Order. It has no comments in response to Questions 1 – 7.

8. How should the Commission "determine a just and reasonable ratemaking methodology to be employed to quantify the cost responsibility of each customer class to pay for generating electric utility-administered demand side management programs"?

Presumably, Commission action regarding DSM portfolios that impacts the rates, terms, and conditions of electric service will apply only to jurisdictional customers, not VEPGA members. VEPGA believes that in the absence of an express statutory directive, its members would neither be obligated to participate in, nor bear any responsibility for the cost of, generating electric utility-administered DSM programs. This result, which is consistent with long-standing Virginia law, recognizes that electric costs incurred by localities are ultimately paid by taxpayer revenues.

The General Assembly may mandate that energy conservation and demand response targets be accomplished through DSM portfolios administered by generating utilities and include in that mandate non-jurisdictional customers like VEPGA members. In that event, and to the extent any such program applies to VEPGA members, cost responsibility should be limited to only those costs directly attributable to the localities' class and, further, should exclude any component intended to guarantee earnings for utilities (including but not limited to incentive payments).

9. **What "class cost responsibility methods [are] used in other jurisdictions," and "would [it] be in the public interest for the Commission to have a similar policy" to other jurisdictions that permit certain customers to be exempt from participating in and/or paying for a utility's demand-side management programs"?**

Certain programs that exempt certain non-residential customers from participating in and/or paying for a utility's DSM programs can be referred to as "self-direct" programs. Such exemption programs are in the public interest because they recognize that certain non-residential customers are not well served by standardized "cookie-cutter" DSM programs. Such customers tend to have energy-intensive operations and to be very familiar with, and knowledgeable about, conservation and energy efficiency, peak load reduction, demand response, and related programs. Such customers typically have long-term experience with implementing such programs, in part because it makes good business sense to do so. As a result, many of these customers have already captured the "low hanging" fruit associated with simpler energy-efficiency improvements, such as lighting upgrades or motor retrofits. To continue to achieve energy savings, these customers require the flexibility to implement projects specific to their needs and

facilities. Exemptions provide that needed flexibility; they also can be structured to reward these customers' past efforts.

Some "self-direct" programs established in other jurisdictions pertain to large commercial and/or industrial customers. In the event VEPGA members were obligated to participate in and contribute to generating electric utility-administered DSM programs, exemptions pursuant to "self-direct programs" would need to be tailored to reflect localities' unique characteristics.

A banking program is a type of self-directed exemption that maximizes customer flexibility and allows for customer implementation of projects specific to their needs and facilities. A banking exemption allows customers to "bank" their individual customer surcharges and then accords them the opportunity to recoup such charges, on a dollar-for-dollar basis, to fund their own efficiency projects and programs. With the opportunity to recoup their surcharges, the ultimate cost to the consumer is fairer and the issue of intraclass subsidies is addressed. This approach also gives customers strong motivation to complete efficiency projects at their facilities and avoids the "cookie cutter" problem where customers are shut out from participating because have already done the types of activities funded by standard program funds. One example of this type of program is Idaho Power's Self-Directed Funds custom efficiency option, which is available to the company's industrial and special contract customers in Oregon. Under this option, Idaho Power establishes an individual account for each participating customer in which the customer's contributions to the company's Energy Efficiency Tariff Rider are tracked. Customers selecting this option have direct use of 100 percent of the funds expected to accrue within their individual account until January 1, 2011 for implementation of cost

effective DSM programs.³ The applicable Idaho Power tariff provides that projects generally must have the potential to save a minimum of 100,000 kWh/year. Given the small size of many Virginia localities, no threshold annual energy savings should apply if this type of program exemption were to be adopted in Virginia and made available to Virginia localities.

Several states' exemptions incorporate a banking-type approach that credits customers for cost effective energy improvements made at their facilities, as these utility examples demonstrate:

- New Mexico – El Paso Electric Energy's *Industrial Customer Self Direct Energy Efficiency Program*. According to El Paso Electric's (EPE's) website, "[i]ndustrial customers who are willing to forgo incentives for undertaking cost-effective energy efficiency measures at their own facilities in exchange for not being charged a share of EPE's EPESaver program costs may apply to opt out of" the EPESaver program.⁴ Under N.M. Public Regulation Commission Rule 17.7.2.11.A, a large energy customer "shall receive approval for a credit for and equal to the expenditures that the customer has made at its facilities on and after January 1, 2005 toward cost effective energy efficiency and load management," upon demonstration to the reasonable satisfaction of the utility or self-direct program administrator that its expenditures are cost-effective. Once approved, the customer receives a credit

³ See Idaho Power Company P.U.C. Ore. No. E-26, available at www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=271.

⁴ Information about El Paso Electric Energy's program is available at www.epesaver.com/optout.html.

that may be used to offset up to 70 percent of the customer's tariff rider used to recover the utility's costs.

- A "large" energy customer is defined in N.M.P.R.C. Rule 17.7.2.7.O as a utility customer at a single, contiguous field, location or facility (regardless of the number of meters at that field, location or facility), with electricity consumption greater than 7,000 MW/year. Requirements regarding both contiguity and consumption would need to be eliminated if this type of program exemption were to be adopted in Virginia and made available to Virginia localities.
- Ohio – AEP's Ohio's *Business Self-Direct and Custom Programs*. AEP Ohio has programs that allow non-residential customers to receive credit for either previously-completed or future energy efficiency and peak demand reduction projects.⁵ Under AEP Ohio's Business Self-Direct Program, non-residential customers may submit previously-completed energy efficiency and peak demand reduction projects (installed after January 1, 2006) and receive either: (1) an incentive payment of 75 percent of the calculated incentive amount under the Business Lighting or Custom Program; or (2) an exemption from the Energy Efficiency/Peak Demand Reduction (EE/PDR) surcharge for a specified number of months, which is determined by the value of the one-time incentive amount and the customer's EE/PDR surcharge obligation. AEP Ohio's Custom Program provides incentives for qualifying future projects that reduce energy consumption and summer peak demand.

⁵ Information about the AEP-Ohio programs is available at www.gridsmartohio.com/savingWork/CIPPrograms.aspx.

- The Self-Direct program is limited to non-residential customers with energy consumption in excess of 700,000 kWh/year. Given the small size of many Virginia localities, no minimum energy consumption level should apply if this type of program exemption were to be adopted in Virginia and made available to Virginia localities.
- Wyoming – Rocky Mountain Power’s *Self-Direction Credit Program*. This program provides participating large electric customers with bill credits equal to 80 percent of an approved project’s cost. The credits can be used to offset 100 percent of the Customer Efficiency Services charge (a DSM surcharge) while the credits remain.⁶
 - Eligibility requirements include either a peak load of 1,000 kW or annual usage of 5,000,000 kWh within the prior twelve months; unlike other exemption programs, requirements can be met by aggregating electric use at meters under common ownership. Again, given the small size of many Virginia localities, no minimum energy consumption level should apply if this type of program exemption were to be adopted in Virginia and made available to Virginia localities.

If the Commission does not support adoption of banking or banking-type self-directed exemptions, then it should consider a competitive solicitation approach, similar to the program in effect in Texas and governed by Texas Public Utility Commission Subst. R. 25.181, *Energy Efficiency and Customer-Owned Resources*. Under the Texas model, which includes both “standard offer” and “market transformation” utility

⁶ Rocky Mountain Power’s Self-Direction Credit Program Manual is available at [/www.rockymountainpower.net/File/File87219.pdf](http://www.rockymountainpower.net/File/File87219.pdf). See also <http://psc.state.wv.us/htdocs/orders/20000-264-18102.htm>.

programs, a commercial customer may propose to its utility the energy efficiency measures the customer intends to implement. The utility then provides financial incentives based on the customer's proposals, which may be paid directly to commercial customers with a peak load equal to or greater than 50 kW. Certain requirements apply, including measurement and verification of quantifiable energy savings. A representative program is offered by Oncor, originally part of TXU Electric Delivery. Oncor offers commercial and governmental facilities with 100 kW or more in energy demand a "Commercial Standard Offer Program" designed to reduce summer peak electrical demand by offering incentives to commercial facilities to install measures that increase their overall energy efficiency.⁷

VEPGA supports exemptions programs that maximize customer flexibility and allow for customer implementation of projects specific to members' needs and facilities. To the extent only "cookie cutter" type efficiency programs are available, then customers with unique requirements or those unable to actively participate should be permitted to opt out.

III. CONCLUSION

In the 2009 session of the General Assembly, the Commission was directed to conduct a proceeding to determine achievable, cost-effective energy conservation and demand response targets than can realistically be accomplished in the Commonwealth through demand-side portfolios administered by generating electric utilities. The Commission must submit its findings and recommendations to the Governor and General Assembly by November 15, 2009.

⁷ Information about Oncor's energy efficiency programs is available at www.txuelectricdelivery.com/electricity/teem/business/default.aspx.

For VEPGA members, the process of identifying and achieving conservation and demand response targets would most efficiently and effectively be achieved through negotiation between VEPGA and Virginia Power. This approach, which is consistent with VEPGA members' long-standing non-jurisdictional status, would ensure that localities and other political subdivisions served by Virginia Power have the necessary flexibility to most reasonably meet those goals. Since many VEPGA members have already implemented conservation and demand side response programs, this approach will take into account factors such as (a) the previous implementation by VEPGA members of certain conservation and demand response measures and (b) VEPGA members' ongoing participation in PJM demand response programs. VEPGA therefore recommends that the Commission, in its report to the Governor and General Assembly, recommend the exclusion of non-jurisdictional customers like VEPGA members from the obligation to participate in and contribute to any DSM program administered by generating electric utilities for jurisdictional customers, but allow non-jurisdictional customers the flexibility to devise such programs through direct negotiation with the electric utility companies.

As explained herein, whatever model is adopted for jurisdictional customers will likely influence contract negotiations with Virginia Power. Consequently, VEPGA also recommends that the Commission support self-direct or opt-out exemptions. Such exemptions further the state's interest in conserving energy because they help ensure that customers have the flexibility to implement energy projects specific to their needs and facilities. Exemption provisions also can be designed to acknowledge and reward the

efforts of customers who have voluntarily funded and made conservation and energy efficiency improvements over the last several years.

Respectfully submitted,

VIRGINIA ENERGY PURCHASING
GOVERNMENTAL ASSOCIATION

By Counsel




Cliona Mary Robb
Christian & Barton, LLP
909 E. Main Street, Ste. 1200
Richmond, Virginia 23219
Phone: (804) 697-4100
Fax: (804) 697-4122
lmonacell@cblaw.com
crobb@cblaw.com

July 31, 2009

CERTIFICATE OF SERVICE

I certify that on this 31st day of July, 2009, a copy of the foregoing was mailed, first-class, postage pre-paid, to the parties listed below.


Cliona Mary Robb /nh

Don R. Mueller
Associate General Counsel
State Corporation Commission
1300 East Main Street, 10th Floor
Richmond, VA 23219

Patrick R. Scanlon, Esq.
Todd J. Griset, Esquire
Donald J. Sipe, Esquire
Preti, Flaherty, Beliveau & Pachios
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332

C. Meade Browder, Jr., Esq.
Office of the Attorney General
Division of Consumer Counsel
900 East Main Street, 2nd Floor
Richmond, VA 23219

Irene A. Kowalczyk, Director
Energy Policy & Supply
MeadWestvaco Corporation
299 Park Avenue, 13th Floor
New York, NY 10171

Kendrick R. Riggs, Esq.
Stoll Keenon, Ogden
2000 PNC Plaza
500 West Jefferson Street
Louisville, KY 40202-2828

Mr. Robert A. Vanderhye
801 Ridge Drive
McLean, VA 22101-1625

Chris S. King
Chief Strategy Officer
eMeter Corporation
2215 Bridgepointe Parkway, Suite 300
San Mateo, CA 94404

Jack Greenhalgh, President
New Era Energy
P.O. Box 121
Williamsburg, VA 23090

Caleb Jaffe
Sarah Rispin
Southern Environmental Law Center
201 West Main Street, Suite 14
Charlottesville, VA 22902

Anthony J. Gambardella, Jr.
Woods Rogers
823 East Main Street, Suite 1200
Richmond, VA 23219

Richard D. Gary, Esq.
Noelle C. Coates, Esq.
Hunton & Williams LLP
Riverfront Plaza, East Tower
951 East Byrd Street
Richmond, VA 23219-4074

David Prezioso, Vice President
Ice Energy Corporation
1357 Linley Trace
Marietta, GA 3056

Meera Ahamed, Esq.
Washington Gas Light Company
101 Constitution Avenue, NW
Washington, DC 20080

W. Todd Benson, Esquire
Piedmont Environmental Council
P.O. Box 460
Warrenton, VA 20188

Pamela J. Walker
M. Renae Carter
Dominion Virginia Power
P.O. Box 26666
Richmond, Virginia 23261

960037.3

FAIRFAX COUNTY GOVERNMENT

FMD'S ENERGY CONSERVATION PROGRAM

DEPARTMENT: Facilities Management Department

DEPARTMENT DIRECTOR: Jose Comayagua

DEPARTMENT BRANCH: Projects Engineering and Energy
Barry Hickey, Assistant Director FMD

PROJECT MANAGERS: Jenna Gorter, PE, CEM, Senior Energy Manager
Jay Yee, Controls Engineer
Ralph Jaquess, Controls Engineer

GOAL: FMD has an internal goal to reduce energy consumption a minimum of 1% per year (measured in KBTUs/square foot) for the buildings in FMD's inventory. This is one of the annual performance measures for FMD. Actual savings have averaged 1.8% per year since 2001 – 12.6% total.

Kbtu/S.F.

Rentable S.F.

HOW SAVINGS ARE CURRENTLY ACHIEVED:

- **Building Automation Systems** - Install and maintain remote computer control of Heating/Ventilating and Air Conditioning (HVAC) systems in buildings.
 - 20-35% Energy savings from shutting down equipment when not needed
 - Over 70 buildings currently under computer control (2-4 systems being added each year)
 - Installation of building automation systems is now standard for all new county facilities.

FAIRFAX COUNTY GOVERNMENT

FMD'S ENERGY CONSERVATION PROGRAM

- Example of savings at John Marshall Library where installation resulted in 28.8% savings in first year after installation:

- **"Energy Cap" Utility Software** – This is a computer software package that provides FMD with a comprehensive database of building utility information. This database is used for analyzing the energy consumption for our buildings. Each utility bill, for each building, is input into the program each month where the data is then manipulated in various ways by using the reporting features of the program. This information allows us to identify high energy use buildings; track changes in a building energy use from year to year, and forecast energy usage for each utility.
- **Temperature Setpoint in BOS buildings:** Establish and regulate temperature setpoints in county buildings to maintain comfort and balance energy consumption.

Offices: Indoor Summer Temperature Range	74 -76° F
Indoor Winter Temperature Range	70 -72° F

- a. The recent BOS adoption of the LOB review item to adjust the temperature settings will revise these temperatures to:

Offices: Indoor Summer Temperature Range	75 -77° F
Indoor Winter Temperature Range	67 -69° F

This adjustment is anticipated to save \$230,000 - \$280,000 annually. These estimates are theoretically based and calculated from historical data, and will vary with outside temperatures.

- **Review New Building Designs** – FMD reviews all new buildings designs prior to construction to ensure they are highly efficient once built. This includes review of architectural systems (window types, insulation, passive solar designs), mechanical systems (chillers, boilers, controls, etc) and electrical systems (lights, occupancy sensors, generators).
- **System Replacement** - When implementing capital renewal projects, FMD routinely incorporates high efficiency equipment (motors, chillers, boilers, and packaged cooling

FAIRFAX COUNTY GOVERNMENT

FMD'S ENERGY CONSERVATION PROGRAM

equipment) to replace old inefficient systems. The energy savings are sometimes difficult to quantify, but this strategy keeps us moving forward with energy conservation as part of our daily work.

PREVIOUS SAVING METHODS SINCE 2001 (NO LONGER ACTIVE METHODS):

- **Energy Performance Contracts** – Upgrades to lighting and HVAC systems specifically to lower energy use. Energy Performance contracts have been in place in FMD for over five years resulting in combined annual energy savings over \$1,000,000. These savings are realized each and every year once an energy project is completed. We have completed energy projects for lighting, HVAC and computer controls in over 130 buildings since program inception. We have completed lighting retrofits in all of our facilities and therefore let our contract expire. Should a need arise for any additional energy performance contract work, we can access the state contracts.

Examples of completed projects:

- Completed Energy Performance Contract valued at \$2,132,000 to upgrade lighting and HVAC systems at the three building jail complex. Annual energy savings \$184,000/yr. This project combined capital renewal requirements with energy saving strategies.
 - Completed Energy Performance Contract valued at \$1,418,000 to upgrade lighting and HVAC systems at the *Juvenile Detention Center and Springfield Warehouse*. Annual energy savings \$87,000/yr. This project combined capital renewal requirements with energy saving strategies.
 - Completed construction on an Energy Performance Contract valued at \$915,000 to upgrade lighting and HVAC systems at the three building Government Center complex. Annual energy savings \$111,500/yr.
- **Meter Totalization** - Occurs when several facilities, particularly in a campus situation, are metered using one meter. This results in potential savings. Recently completed a meter totalization project at the Public Safety Complex to combine electric meter billings. Annual savings \$110,000/yr.

ADDITIONAL ENERGY ACTION ITEMS:

- **Outreach** – NACO Change to light program. Won first place award for the large population category in 2006. We also continued our efforts afterwards to get more pledges. Promoting this program did not improve energy efficiency within County buildings, but it encouraged County employees to extend conservation efforts into their personal lives.
- **“Cool County” Program** – FMD is an active participant in this program development.
- **Cost management strategy** – participation in the MWCOG Natural gas reverse auction allowed us to purchase gas in bulk and achieve a lower cost per therm.
- **Annual rate schedule evaluation** – based on the previous year's usage, we determine if we are on the best electric rate schedule to lower our costs.

FAIRFAX COUNTY GOVERNMENT
FMD'S ENERGY CONSERVATION PROGRAM

POTENTIAL FUTURE SAVING OPPORTUNITIES:

- Consider Web Stat based energy management control system to provide remote control access via the internet to certain facilities that do not have EMCS in place. This could eliminate the need to manually adjust temperature settings using maintenance staff.
- Energy outreach. Designate within each agency, an energy point of contact to assist in energy matters within the agency.
- Training program for employees to inform them of their role in energy conservation. For instance, turn off computers (except Thursday) to reduce the energy consumption, unplug chargers when not in use, turn vending machines off at night.
- Continue to monitor feasibility of renewable energy projects, such as solar, and implement at that time.
- Prioritize equipment replacements based on maintenance needs and energy consumption.
- Work with Capital Facilities to establish baseline energy usage targets for new building designs.

970118

Fairfax County Public Schools

Energy Conservation Efforts

Fairfax County Public Schools (FCPS) spends about \$42,000,000 annually on its electric, oil, gas and water utilities. The Office of Facilities Management is tasked to keep this bill as low as possible through development and implementation of conservation programs. FCPS has had an active and aggressive energy management program since 1978, and is a leader among school systems in Virginia and nationwide in minimizing the use and cost of energy.

Some highlights of energy conservation programs at FCPS:

- FCPS has a staff of ten technicians and engineers dedicated to operating energy management control systems and to conserving energy.
- Over 25 million square feet of buildings are under computerized energy management control. This effort began in 1980.
- Since 2002 FCPS has invested over \$21 million in 107 facilities under an energy saving performance contract.
- FCPS engineers monitor utility bills and perform energy audits of buildings to find energy and water conservation opportunities.
- FCPS has initiated a pilot program in five high schools intended to explore and gain experience with advanced metering and electricity demand reduction through PJM load curtailment programs.
- FCPS installs high efficiency HVAC, lighting system and building envelope features in all facilities during new construction and renovations in order to minimize energy consumption.
- FCPS uses US EPA Energy Star benchmarking system to identify energy saving opportunity for 192 schools.

Loudoun County Public Schools

LCPS developed its Energy Improvement Plan in partnership with Energy Education, and has been continuously been implementing the plan since the 1993-1994 school year. Part of the program includes a continuous educational process that focuses on each school's faculty while implementing practical energy conservation procedures.

This conservation program addresses literally thousands of ways our schools use energy and other utilities. In addition to working with individuals to create habits that are energy efficient, we tackle many big energy users in our buildings heating and cooling systems, chillers, irrigation systems, kitchen cooking systems, lighting and others. The following pages list examples of areas where LCPS focuses attention in the ongoing effort to reduce the use of energy throughout the school system without impacting the educational environment while ensuring efficient and effective stewardship of public resources. The end of this Exhibit shows the overall conservation program results to date.

EXAMPLE: Verified Performance.

We verify our savings and success using a computer program called EnergyCAP to analyze our utility bills. In addition to verifying savings, the program helps to see where to look for more savings, and to detect billing errors. One of the new things being offered to the community by the EnergyCAP team is GreenQuest. This is a web site that allows an individual to use the same software that we use to professionally manage energy in our schools, in their own homes. GreenQuest is a free personal energy information website provided to the world by Loudoun County Public Schools. We recommend that everyone use GreenQuest for energy management, utility bill tracking, auditing, reporting, greenhouse gas tracking, and more. The website is <http://lcps.mygreenquest.com/>.

EXAMPLE: Systems Audits.

A systems audit process was started in July 2008. Audits are performed by the LCPS Energy Education team in conjunction with the LCPS Supervisor of Mechanical Trades/Mechanical Engineer. Certifications of these LCPS staff members include: Certified Energy Manager, Certified Energy Auditor, Certified Demand Side Management Professional, Certified Master Electrician, and Certified Master Plumber. The multi-year goal of this audit process is to seek out and identify energy conservation recommendations at all Loudoun County Public Schools' sites. The first round of schools were chosen based on which would present the greatest opportunity for reduced energy cost, increased comfort to facility users, and improved equipment maintenance. As a result of the Mechanical System Audit process conducted at the first four schools, 193 recommendations have been identified and implemented in the first year of this initiative.

EXAMPLE: Energy Star Buildings Benchmarking

LCPS has officially adopted the Energy Star Program created by the US Environmental Protection Agency and the US Department of Energy. A building that earns an ENERGY STAR Label Award uses less energy than 75% of similar buildings in the US Department of Energy's Commercial Building Energy Consumption Survey (CBECS.) Loudoun County Public Schools earned seven ENERGY STAR Label Awards for 2008 (six schools and one support building.) In 2009, we anticipate earning 25 ENERGY STAR Label Awards (24

schools and one support building.) Through the continued efforts of Facilities Services Staff and the Energy Education Team, LCPS has been able to quadruple the number of ENERGY STAR Label Award-winning schools we have in just one year. Striving to attain an Energy Star is an excellent way to foster energy conservation in buildings.

EXAMPLE: Education

Part of the program is to provide educational opportunities to students that complement the program of studies offered through the standard LCPS curriculum. These educational opportunities are also offered to the community. In addition, in the fall of 2008, Loudoun County Schools recognized "National Energy Conservation Month." That October, fliers were sent out each week. These contained information that focused on the following areas:

Week 1 - (Oct 3) Kick-Off

Week 2 - (Oct 10) Make the switch, reduce your use.

Week 3 - (Oct 17) Reducing energy use in transportation.

Week 4 - (Oct 24) Reducing energy use through recycling.

Week 5 - (Oct 31) Reducing energy use through water conservation.

The fliers were distributed to each school with instructions to distribute them to faculty and staff. All facility users were encouraged to implement energy savings actions. In addition, a representative from Dominion Virginia Power was available for one day in the lobby of the school system's administration building. A table was set up and energy savings information and tools were distributed. The representative also set up a computer where individuals' accounts could be looked up for answers to customers' questions.

EXAMPLE: Student Involvement

With the encouragement of the Superintendent, a contest was developed. The goals were to create an increased awareness of energy savings habits, foster student involvement in energy savings practices, recognize student achievement, and experience energy savings due to reduced lighting usage. Students were to create a design for a light switch plate sticker that encourages all facility users to turn off the lights in unoccupied areas. A feature of the contest is the fact that Dominion Virginia Power, the Loudoun Education Foundation, and the Northern Virginia Electrical Cooperative (NOVEC) each provided generous donations to help make this contest happen as part of their commitment to community service and energy use reductions. The entire cost of the grand prizes was supplied by these contributions. This is truly an example of collaboration between industry, associations, and the public schools in the efforts to reduce energy use. During the awards presentation, one potential benefit of the contest was explained: If lights are turned off for one additional hour each school day in a classroom with 16 four-lamp light fixtures, LCPS will avoid spending more than \$25 per school year in that classroom. With well over 2,000 classrooms, the potential of avoiding more than \$50,000 in expenses each school year exists.

EXAMPLE: Renewable Energy

LCPS currently uses over 18 KW in Solar Powered Flashing signals. In addition, Loudoun Valley HS utilizes solar technology to illuminate the School's Sign. This is an 85 watt system.

EXAMPLE: Demand Response

LCPS Piloted the PJM Demand Response Program at Stone Bridger HS. This site achieved its lowest ever annual energy use levels in FY09.

EXAMPLE: Capitol Improvements

Over the 15 year period that the Energy Conservation Program has been in place, numerous building upgrades have been implemented. In an effort to give an example of the types of energy savings technologies employed throughout Loudoun County Schools, the following profile from the Energy Star Portfolio Manager for Meadowland ES is respectfully submitted.



The goal of Loudoun County Public Schools is to reduce energy usage and ensure efficient and effective stewardship of public resources without impacting the educational environment. This energy use philosophy began in 1992, when the district's Superintendent, along with the Loudoun County Public School Board, started a formal Energy Conservation Program. In 1998, LCPS became an ENERGY STAR partner. Through this

partnership, LCPS accessed ENERGY STAR tools and resources to help them incorporate new and innovative technologies into HVAC and lighting retrofit projects planned for Meadowland Elementary School. By the end of the summer in 2003, Meadowland ES had the necessary upgrades to achieve maximum comfort for the learning environment while improving energy performance. These upgrades, combined with a partnership with Energy Education Inc., set the stage for this school to earn the ENERGY STAR in 2008. Efficient building systems combined with the building occupants' efforts to reduce daily energy use resulted in a "climate for success." At Meadowland ES, students, faculty, and staff all do their part to help the environment by taking individual action to reduce energy use.

The district invested \$1.9M in energy efficiency improvements for Meadowland ES. The improvement project focused on two areas: HVAC and lighting. The following HVAC equipment was upgraded: electric boilers were replaced with high efficiency gas pulse boilers with hot water reset capability; the existing air-cooled chiller was replaced with a more efficient chiller system; and VAV air handlers were replaced with new units which included VFDs on supply fans and outside air track dampers capable of measuring outside air requirements. In addition, rooftop package units were installed on the multipurpose room and cafeteria to give the school the ability to zone HVAC operation for after hour activities. The existing pneumatic control system was replaced with Trane Tracer Summit DDC controls which enabled monitoring, alarms, and scheduling from the main office. The lighting portion of this project consisted of a T12 to T8 replacement and the installation of energy-efficient LED exit signs.

Communications:

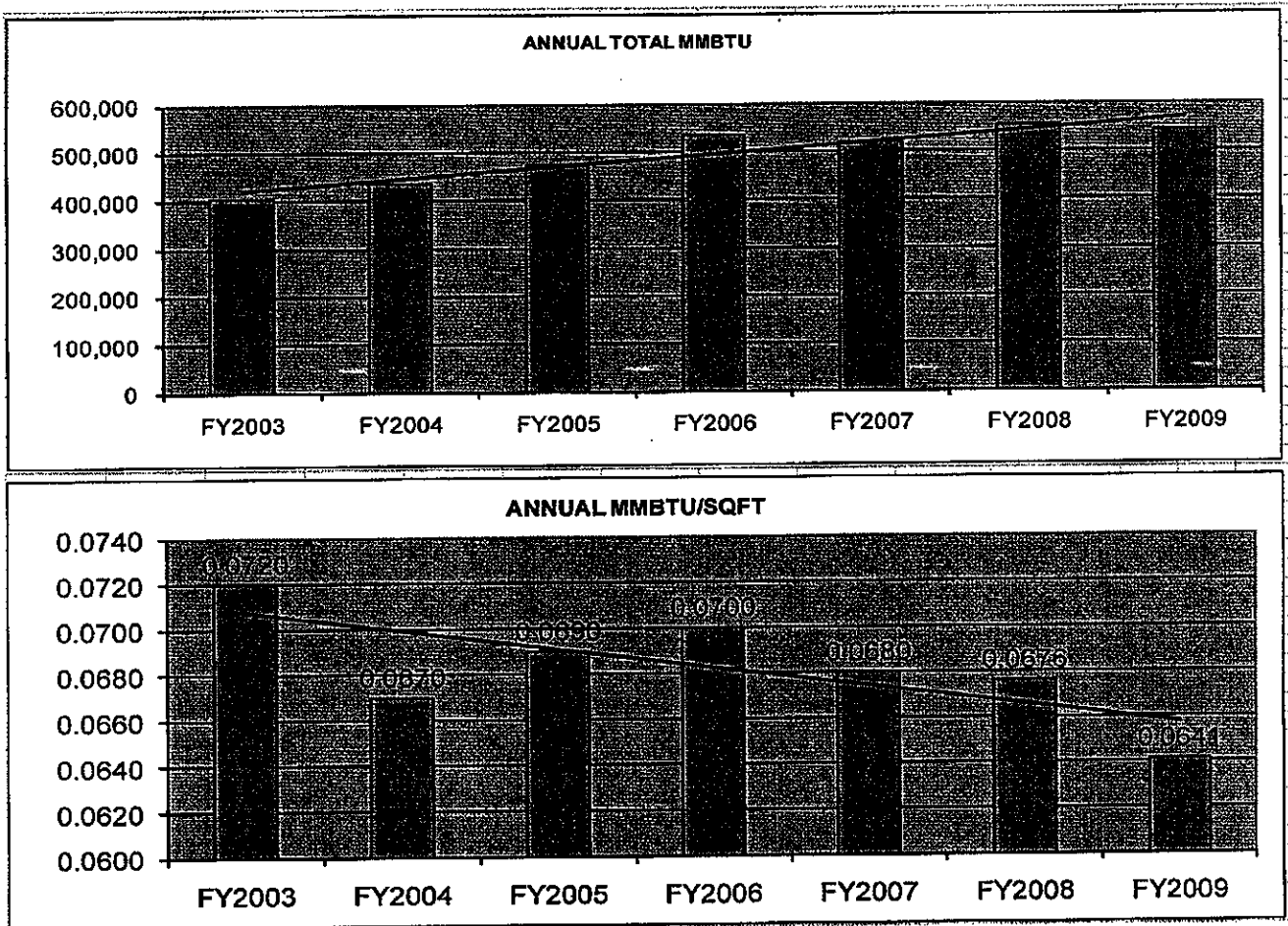
The people-oriented Transformational Energy Management Process developed by Energy Education is a significant component of the district's comprehensive energy conservation program, and site visits to the school to identify opportunities and discuss savings potential with students and faculty were conducted. In addition, the school conducted the following outreach:

- Annual updates on current energy use trends are shared with the school's administration and faculty.
- A press release was distributed to honor the ENERGY STAR qualified school.

Testimonial: "Meadowland Elementary School is the perfect example of how energy use reductions can occur in older facilities when technology is properly chosen, installed, and operated, by conscientious, knowledgeable energy users."

Results

LOUDOUN COUNTY SCHOOLS ENERGY USE DATA



Notable Achievements

Although overall energy use has increased due to the construction of new schools, use in BTU per Square foot has been on a downward trend for the last 7 years. Over this period of time, LCPS has added over 2.5 million square feet.

Through self-directed energy conservation improvements, Loudoun County Public Schools, on two occasions, has been able to reduce the overall annual use of energy from year to year despite growth in new square footage.

By implementing a proven transformational energy management program focused on behavior, and combining this with practical energy conservation improvements, Loudoun County Public Schools has saved over \$31 million on utility costs over the last 15 years. This is more than a 25% reduction in overall energy costs.

Loudoun County Public Schools Conservation Program 1994 to April 2009

Loudoun County VA

Energy CAP

Cost Avoidance Program

Energy Conservation Program

April 2009

Cumulative Cost Savings

Expected Energy Costs	\$116,503,255
Actual Energy Cost	\$86,248,290
Program Savings	\$30,254,965



Expected Energy Costs

Amount you would have spent on energy without energy management program.

This is the base year usage adjusted for changes in weather, equipment, schedules, occupancy and prices

Actual Energy Costs

Actual utility costs for electricity, gas, water, sewer, etc obtained directly from bills.

Program Savings

The difference between Expected and Actual Costs, calculated in accordance with the International Performance Measurement & Verification Protocol. Does not include savings attributable to reduced equipment maintenance and replacement costs and other collateral benefits. These savings can increase the program savings up to 20%.

Cumulative Greenhouse Gas Reduction

Energy Reduction Impact: 1,808,745 MMBTU 567,966 equiv. metric tons of CO2

This is equivalent to the following:

Passenger cars not driven for one year:	101,943
Tree seedlings grown for 10 years:	14,527,438

July 31, 2009

VIA Electronic Filing

Joel H. Peck, Clerk
Document Control Center
State Corporation Commission
Tyler Building, 1st Floor
1300 East Main Street
Richmond, VA 23219

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 electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly Case No. PUE-2009-00023

Dear Mr. Peck,

Pursuant to the Commission's April 30, 2009 Order Establishing Proceeding and Setting Evidentiary Hearing in the above referenced case, please find enclosed for filing on behalf of respondent Piedmont Environmental Council an Electronic Filing of its Opening Brief.

If you should have any questions, please do not hesitate to contact me.

Sincerely,

Robert G. Marmet

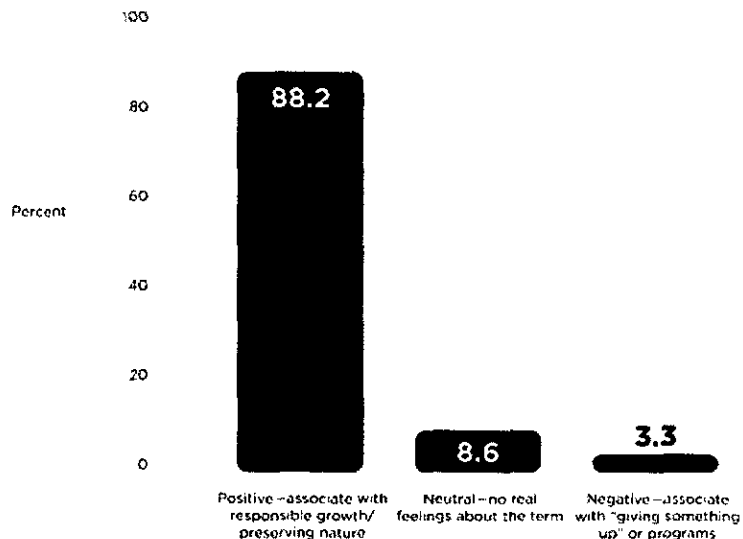
Brief of
The Piedmont Environmental Council

Before the State Corporation Commission of Virginia
PUE-2009-00023

The Piedmont Environmental Council (PEC) is pleased to offer its comments on pending case No. PUE-2009-00023, which concerns Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly and whose aim is to consider achievable, cost-effective energy conservation and demand response targets. Taking part in several proceedings over the past years, PEC has championed energy efficiency as the first of several strategies needed to meet Virginia's demand for electricity.

Estimates of potential savings through energy efficiency and conservation by reputable independent researchers and organizations support the conclusion that substantial reductions are achievable. The assessment released just this week by McKinsey and Company concludes that a 23% reduction is achievable by 2020. Now is the time for the Virginia State Corporation Commission (SCC) to implement a dynamic suite of energy conservation measures. The increasing body of literature documenting the potential for cost effective, verifiable demand reduction programs combined with the public's increasing acceptance of energy efficiency as a low-cost solution to energy needs offers a window of opportunity for the SCC to provide direction in the Commonwealth. The public is looking for leadership that will aim high rather than accept a minimal effort.

As found in the Energy Pulse 2008 survey conducted by the Shelton Group and the Alliance to Save Energy, a full 88.2% of the public has a positive impression of the word “efficiency”—as in “energy-efficiency”—associating it with responsible growth and the preservation of nature. With this in mind, PEC strongly recommends that the SCC urge the Virginia General Assembly to enact legislation that will promote energy efficiency and conservation of far greater than 10 percent by 2022. PEC offers this brief to comment on a few of the issues or concerns raised by the utilities and other respondents and to propose that the State set a higher, but still achievable and cost-effective, goal for itself.



How do you feel about the term “efficiency,” as in “energy-efficiency”?

energy pulse

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1

While PEC is not presenting expert testimony, we are broadly supportive of the position of the Southern Environmental Law Center (SELC) as well as Mr. Robert Vanderhuyse and want to see future legislation include, at the very least, a three to five tier

¹ Slide from the Shelton Group’s *Energy Pulse 2008* survey

inclining block rate design coupled with advanced metering information (AMI) and demand-side management (DSM) deployment. In addition, PEC would like to advance the following remarks on the testimony provided by Virginia's largest generating utility, Virginia Electric and Power Company.

With regard to the Company's conclusion that the "ACEEE Report's findings are overly ambitious²," we disagree and provide a sample list of reports and corresponding energy efficiency projections that have been published in the past two years:

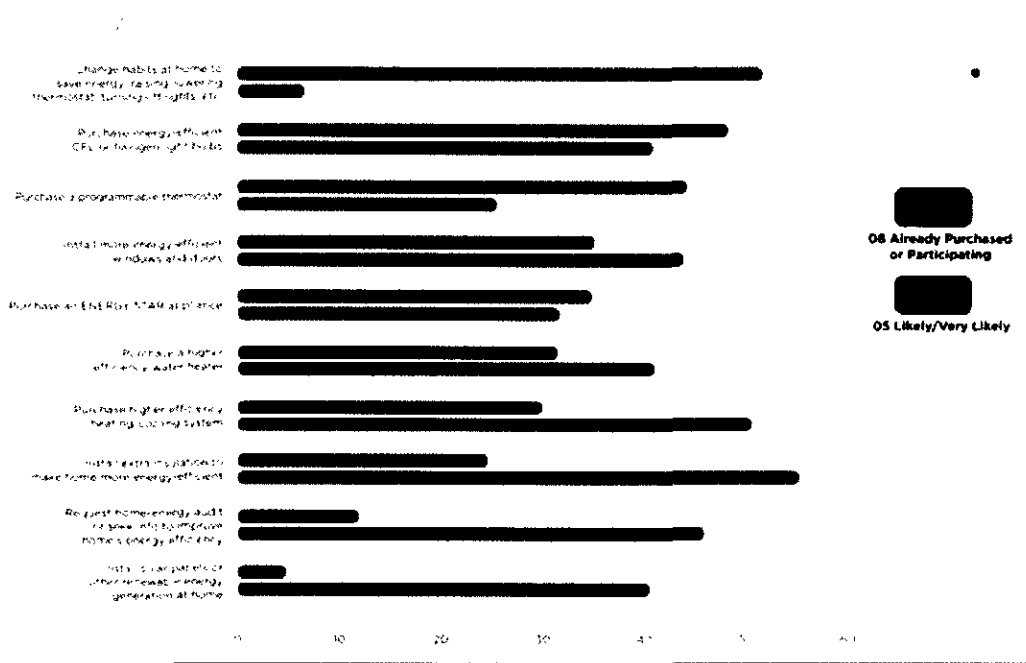
1. McKinsey and Company, "Unlocking Energy Efficiency in the U.S. Economy" (July 2009) — Nationwide reduction by 23 percent by 2020 in annual energy consumption from a business-as-usual (BAU) projection;
2. Federal Energy Regulatory Commission (FERC) Staff Report, "A National Assessment of Demand Response Potential (June 2009) — Under the "Achievable Participation Scenario," reduction in peak demand is 14 percent by 2019 compared to a scenario with no demand response programs, while in the "Full Participation Scenario," a 20 percent reduction in peak demand is achieved by 2019;
3. American Council for an Energy-Efficient Economy (ACEEE), "Energizing Virginia; Efficiency First" (September 2008) — In the "medium scenario," the ACEEE estimates a reduction of 26 percent by 2025 in summer peak demand through energy efficiency and demand response policies.

² Company testimony, pg 7

Evidently, ACEEE's numbers are in line with the figures provided by other reputable sources and indicate that the ten percent goal, which the Company refers to as an "aggressive" target, is in reality conservative and quite cost-effectively achievable.

In addition, the Company cites "customer acceptance" as a concern and claims that its customers may "view increases or decreases in their bills as an indication of changes in their rates instead of changes in their usage;" in other words, they would not be able to "see" their savings³. For this problem, PEC suggests AMI, or the installation of in-home displays that allow customers to monitor their own energy usage through a real-time feedback loop --a solution the company is already pursuing in case PUE-2009 00081. Moreover, we include another slide from the Alliance to Save Energy and the Shelton Group's Energy Pulse 2008 survey to demonstrate that many more people than originally anticipated in fact changed their habits (by raising/lowering the thermostat, turning off lights, etc.) between 2005 and 2008 in order to save energy and money. People only need the incentive, and that can be provided by the utilities through inclining block rates and enhanced by the installation of AMI and the establishment of DSM programs.

³ Company testimony, pg 16-17



Current and Likely/Very Likely Home Products and Activities 2005-2008

energy pulse

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Lastly, we wish to address a point brought up by the Company that concerns the building of new infrastructure. As is written in the testimony, “If DSM targets are too aggressive and investments in new generation are not made in a timely manner, then economic development can be hampered because there could be a shortfall of available, reliable and affordable electricity”⁵. The investment required by new generation or long distance transmission is *much* greater than the investment required by energy efficiency programs. The construction of more power plants and more transmission is very likely to overload the grid, thereby making it even less reliable. Amory Lovins, a leading energy expert and chairman of the Rocky Mountain Institute, believes that large power plants are a relic of the past and favors instead a “diversified portfolio of many small, distributed

⁴ Slide from the Shelton Group’s *Energy Pulse 2008* survey
⁵ Company testimony, p. 18

units⁶” which carries much less financial risk and make the grid less susceptible to frequent and extensive interruptions.

As several of the reports mentioned above noted, there is great potential in Virginia for energy efficiency programs, and we must not squander the opportunity to invest in the future well-being of our State. According to the June 2009 FERC report, “The prevalence of central air conditioning plays a key role in determining the magnitude of Achievable and Full Participation scenarios. Hotter regions with higher proportions of central air conditioning, such as the South Atlantic [which includes Virginia] ... could achieve greater demand response impacts per participating customer from direct load control and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the Achievable and Full Participation scenarios, where dynamic pricing plays a more significant role, than in the Expanded Business-as-Usual scenario.”

A 2005 Rand Corp. report entitled “Regional Differences in the Price-Elasticity of Demand for Energy” also observed that “the impact of energy efficiency would be greater in areas such as the South in which the intensity of electricity use has been growing more rapidly than in other regions.” The common thread of these reports is clear: With moderate effort and relatively low investment, there are a number of good opportunities to achieve important reductions in energy use in Virginia. A modest goal of ten percent by 2022, which falls very much towards the low-end of the spectrum provided earlier is inadequate to address the Commonwealth’s need for energy efficiency. This docket offers an opportunity for the SCC to set the bar higher and challenge all Virginians to rise to the challenge. The outcome of this docket could be to raise the

⁶ “Does a Big Economy Need Big Power Plants?” Stephen J. Dubner, The New York Times Freakonomics blog.

quality of life of Virginia's residents. Under the leadership of this Commission the Commonwealth could see a growth in investments in statewide energy efficiency and conservation, which could produce thousands more jobs, a higher Gross State Product, and lower utility bills for low-income and higher income residents alike.

PEC is encouraged by the recent interest shown by the state as well as by both rural electric cooperatives and investor-owned utilities in energy efficiency and demand-side management. Additionally, we look forward to participating in the SCC hearing this September and to reviewing Virginia Electric and Power Company's recent request for approval to implement a series of new demand-side management programs in the filing of case PUE-2009-00081.



July 31, 2009

BY ELECTRONIC FILING

Hon. Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street
Richmond, Virginia 23219

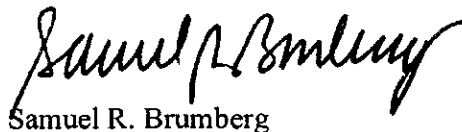
*Re: In the matter of determining achievable, cost-effective energy conservation and demand response targets that can realistically be accomplished in the Commonwealth through demand-side management portfolios administered by each generating electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly
Case No. PUE-2009-00023*

Dear Mr. Peck:

Pursuant to Ordering Paragraph No. (7) of the Commission's April 30, 2009, *Order Establishing Proceeding and Setting Evidentiary Hearing* in the above-referenced docket, attached you will find the *Comments of the Virginia Electric Cooperatives*.

Thank you for your attention to this matter.

Sincerely,



Samuel R. Brumberg

E-mail: samuel.brumberg@leclairryan.com
Direct Phone: 804.968.2981
Direct Fax: 804.916.7278

4201 Dominion Boulevard, Suite 200
Glen Allen, Virginia 23060
Phone: 804.270.0070 \ Fax: 804.270.4715

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ATTORNEYS AT LAW \ WWW.LECLAIRRYAN.COM

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
at Richmond**

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response targets that can be realistically)
accomplished in the Commonwealth through)
demand-side management portfolios administered)
by each generating electric utility identified by)
Chapters 752 and 855 of the 2009 Acts)
of the Virginia General Assembly)

Case No. PUE-2009-00023

**COMMENTS OF THE
VIRGINIA ELECTRIC COOPERATIVES**

Pursuant to the Virginia State Corporation Commission's ("Commission") April 30, 2009, *Order Establishing Proceeding and Setting Evidentiary Hearing* ("Order") in this proceeding, A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative, along with the Virginia, Maryland & Delaware Association of Electric Cooperatives (collectively, the "Virginia Cooperatives" or "Cooperatives") hereby join in filing these *Comments of the Virginia Electric Cooperatives*.

BACKGROUND

The Commission initiated the instant proceeding in response to a mandate from the General Assembly to conduct a public proceeding—including an evidentiary hearing—to determine 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 electric utility identified in the statute. The Commission invited a broad spectrum of comments from the investor-owned utilities serving the Commonwealth, industry participants, environmental groups, and the public at large. To date, several of these constituencies have joined the instant proceeding, including two industrial user groups, the Old Dominion Committee for Fair Utility Rates and the Virginia Committee for Fair Utility Rates, and two environmental groups, the Southern Environmental Law Center and the Piedmont Environmental Council.

While the Virginia Cooperatives are neither subject to the requirements of the statute nor mandatory respondents in this proceeding, what follows are the Virginia Cooperatives' comments relative to consideration of the issues presented in this case. The Virginia distribution cooperatives occupy a unique position in the market, and therefore the Cooperatives have chosen to comment generally on the issues of demand response and energy efficiency programs, and to highlight various efforts undertaken by the electric cooperative community in Virginia to promote such efforts among their members and the public at large.

COMMENTS

I. Introduction

The Virginia Cooperatives are organized as utility consumer services cooperatives under the laws of the Commonwealth of Virginia. As such, the Cooperatives are owned by and operated for the benefit of their member-consumers, and their operations are conducted on a not-for-profit basis. A cooperative's primary corporate objective is to provide safe and reliable retail electric service to its member-owners at the lowest reasonable cost.

II. Historical Perspective

Generally speaking, the Cooperatives are neither generating nor transmitting utilities, and as such are not subject to the statute as "generating electric utilities." Each of the Cooperatives purchases the power needed to serve its members at wholesale through wholesale power purchase contracts. The cost of wholesale power comprises approximately, and on average, seventy percent (70%) of the total cost of delivering retail electric service. Some of the Cooperatives are members of Old Dominion Electric Cooperative ("ODEC"), a FERC-regulated generation and transmission cooperative, and each ODEC-Member Cooperative has a wholesale power contract with ODEC. Similarly, the non-ODEC Cooperatives have wholesale power contracts with other providers. Depending on the terms of each Cooperative's wholesale contract, various incentives may be in place to encourage demand response. Just as retail consumers can realize savings by using and buying less electricity, distribution cooperatives and their members benefit from reduced wholesale purchases. To save on costs, all of which ultimately are passed on to their members, each of the Cooperatives, as a purchaser of

power, has an incentive to conserve energy and promote efficiency. Those Cooperatives with a demand component to their wholesale power rates also have an incentive to practice and promote demand-side management, unlike those Cooperatives that purchase power at wholesale through an energy-only contract.

The Cooperatives have, over many years, been committed to conservation, energy efficiency, and demand response efforts and programs. For the Cooperatives, efficiency, conservation, and demand management are regarded as a practical necessity, not an afterthought. For decades, the Cooperatives have been engaged in efforts to promote efficiency, reduce consumption, and lower peak demand. Management efforts usually are of two types: system-wide efforts, uniformly implemented across distribution systems and affecting all members, and voluntary programs, available at a member's option.

Two programs that are uniformly implemented by the Cooperatives and that affect all member-owners are (i) line loss prevention and (ii) uniform voltage reductions. Line loss prevention, even at the distribution level, helps to improve system reliability and stability and to reduce the waste of electricity. Temporary voltage reductions reduce overall consumption, while maintaining a minimum voltage necessary to operate members' equipment, in times of increased demand. All members participate in these programs simply by being on a cooperative's distribution system. These programs reduce consumption, but the reductions take place over the entire cooperative distribution system and result in a reduced volume of electricity purchased at wholesale.

Voluntary programs are offered to members by a majority of the Cooperatives. In encouraging their members to engage in conservation efforts, the Cooperatives are not "starting from scratch." At the retail level, the Cooperatives have had direct load control

programs in place for many years. The most prevalent example of direct load control for residential retail customers—the majority of the Cooperatives' members—are residential load control switches for water heaters and air conditioners. The Cooperatives also offer interruptible rates for commercial and industrial class customers.

Residential load control switches operate by cycling off the appliance in question at certain intervals to shut off its consumption of electricity. This cycling activity is done in such a way as to make the impact on members' quality of life negligible. The Cooperatives have over 124,000 of these switches installed at members' homes. This represents an average penetration rate of approximately twenty-five percent, representing a good level of participation on the part of the Cooperatives' members.

Many Cooperatives also offer various forms of time-of-use or interruptible rates to their commercial and industrial members. While these are designed to manage demand, the Cooperatives also assist these customers with monitoring energy use and identifying and implementing efficiency measures.

Additional programs encourage efficient use of energy by the Cooperatives' predominantly residential, retail members and provide consumer education on conservation and energy management. These programs, some of which are already being implemented, include appliance recommendations, home energy auditing, recommendations for other home systems and equipment, such as heating, ventilation and air conditioning, lighting recommendations, and consumer education programs that include tips on saving energy.

III. Consumer Education

Encouraging a member to change his or her lifestyle to save on electricity is a process that requires consistent and persistent consumer education over time. This is all the more necessary because of the demographic composition of the Cooperatives' service territories; more than ninety percent of the Cooperatives' members are residential, retail accounts. Any reduction in use that occurs as a result of a consumer's behavioral change must be sustained for any savings to be meaningful, and this applies especially to residential retail consumers.

To that end, consumer education is another important part of the Virginia Cooperatives' efforts to promote efficiency and conservation. The Cooperatives believe that all parties—regulators, utilities, consumer groups, and users—have a role to play in consumer education. The Virginia Cooperatives deeply value their relationships with their members, and they take the obligation to serve their members at the lowest reasonable cost very seriously. The members are the owners of the Cooperatives. There are several avenues for consumer education, all of which are regularly employed by the Cooperatives in an attempt to make efficiency efforts part of their members' everyday lives.

A. *Cooperative Living*

The Virginia, Maryland, and Delaware Association of Electric Cooperatives publishes *Cooperative Living*, a monthly magazine providing news and information to cooperative members. Each volume includes a customized insert that pertains to each individual member Cooperative. Almost half a million Cooperative members in Virginia receive *Cooperative Living*. Each issue of *Cooperative Living* contains an article on an

energy efficiency topic and an energy efficiency tip for consumers. This is in addition to any information published by individual Cooperatives in the member insert pages.

B. Local Events and Programs

The Cooperatives regularly attend community events. These community events include local fairs, expos, energy efficiency seminars, lectures, and panel discussions. In delivering on the cooperative value of “Concern for Community,” the Cooperatives view themselves as important community institutions whose employees live and work in the communities served by the Cooperative. Attending, participating in, and sponsoring local events is one way to build community support for efficiency and conservation efforts.

As an example, in January 2009, the Virginia Cooperatives donated over 4,000 compact fluorescent replacement light bulbs (“CFLs”) to the Commonwealth, enabling Virginia to install CFLs to replace all of the incandescent lights in Virginia’s State Parks. This is but one example of a cross-community program to promote efficiency, part of the Cooperatives’ wide-ranging community engagement efforts in consumer education.

C. Other Efforts

The Cooperatives’ other efforts to promote efficiency and conservation through consumer education include:

- A compact fluorescent light bulb savings coupon and bulb give-away program;
- An energy efficiency home retrofit consumer loan program, in conjunction with Virginia’s Farm Credit agencies;
- Surveys and polling efforts to allow the Cooperatives to gain a better understanding of consumer behaviors and willingness to participate in additional voluntary efforts for conservation and usage shifting;
- Offering an energy efficiency calendar;
- Additional voluntary load reduction programs;

- Additional rollout of air conditioning cycling devices and the study of various cycling strategies and consumer reaction;
- Educational efforts through clinics held at local hardware stores; and
- Work in classrooms and in schools, including safety seminars and printed materials for students to take home.

IV. The Ten Percent Goal and Policy Objectives

A. The Ten Percent Goal

The Commission's *Order* does not specifically mention the Virginia Energy Plan's proposed goal of reducing electric use by ten percent of 2006-level retail consumption through conservation and energy efficiency efforts (the "Ten Percent Goal"). Despite not being mentioned in the Commission's *Order*, it is important to discuss the Ten Percent Goal here because the targets being considered in this proceeding will have an effect on the Commonwealth's ability to meet that goal. The Ten Percent Goal is to be achieved by 2022. With a clear understanding of how the Ten Percent Goal is to be measured, as described below, Cooperatives support the effort to achieve that goal. In the Cooperatives' service territories, when viewed against what a 2006 base year would have been absent current load management programs, part of the Ten Percent Goal has already been achieved.

If obligated to participate and use 2006 as the base year for determining demand savings, the Cooperatives would urge that the base year's usage data for establishing the Ten Percent Goal be considered exclusive of existing load management efforts. The Cooperatives believe that allowing for cumulative savings, adjusted to account for reductions implemented in prior years, would be a fairer, more reasonable measure of the progress made toward the Ten Percent Goal. The measurement of the Ten Percent Goal

must also take into account the fact that distribution systems are not stagnant; rather, they grow and change, expanding and contracting over time as people move and new buildings are constructed. Whether reductions in demand come from utility programs or from non-utility curtailment service providers, they should all count toward meeting the Ten Percent Goal. Weather also impacts system demand. When viewed in historical terms, demand should be weather-normalized if it is being used to measure progress toward the Ten Percent Goal, and should also take into account the varying consumer mix among the utilities.

Finally, the Ten Percent Goal should recognize that simple reductions in the use of electricity may not equal *true* energy savings. The Virginia Energy Plan rightfully recognizes that energy savings must be across all fuel sources. The use of electricity could be significantly reduced if all homes switched from electric heat to natural gas heat, but such a move may not result in any real energy savings. Rather, use has simply been switched from one fuel to another. The ultimate goal will be disserved if fossil fuels are merely moved from consumption at the point of generation to consumption at the end-user's delivery point. Similarly, if usage is shifted to a different time, this may achieve a demand reduction but not an overall energy savings, and in some cases may actually increase energy usage. Finally, if a large load was to switch utilities, or even switch to or from an unregulated utility such as a municipal utility, this might change usage data from one utility to another, but not achieve real savings, and may prove difficult to measure. Ultimately, the Ten Percent Goal should reflect a level playing field in these areas.

B. Policy Objectives

Rather than support mandates, the Cooperatives support programs that are responsive to consumers and that help them make economically-rational decisions, supported by the market. Bearing this in mind, the Cooperatives, as a general rule, would opt to assign costs to and recover costs from the customers incurring that cost or receiving a benefit.

When their members' benefits increase, costs decrease, or both, the Cooperatives will offer demand response programs, special rate structures, or other efficiency programs. For this reason, the Cooperatives oppose a "public benefit" fund or other distributive mechanisms, including the so-called "societal test" for cost-effectiveness. Costs should be tied directly to the group or rate class causing the utility to incur those costs or to the group or rate class receiving a benefit from dollars being expended.

The Cooperatives also would note that the law provides specific financial incentives for investor-owned utilities to implement demand response programs, incentives that do not work for not-for-profit electric distribution cooperatives. Investor-owned utilities have an economic incentive to invest in demand response programs because the law assures them that they will eventually recover their costs, including a margin.¹ For distribution cooperatives, each dollar spent on promoting and implementing demand response and efficiency initiatives ultimately must be recovered from their members. An increased margin or guaranteed return generally provides no embedded incentive to an electric cooperative.

¹ 2009 Va. Acts 824.

V. Time of Use and Interruptible Rates

As the Commission is well aware, one of the impediments to large-scale implementation of residential retail demand response is the inability to send pricing signals directly to residential consumers to encourage them to change their usage patterns and behavior. The General Assembly has asked the Cooperatives to report on such impediments and their impact, and render a report to the General Assembly.² Encouraging consumers to alter patterns of electricity usage requires consumers to understand how their usage affects their energy costs and the ability to provide pricing signals to residential consumers.

Time-of-use rates for residential retail consumers of distribution cooperatives would need to be coordinated at both the retail and wholesale levels to be effective. Currently, only limited infrastructure exists to support this on the Cooperatives' distribution systems, and the costs of large-scale residential retail infrastructure installation would be extremely high. In addition, the Cooperatives cannot take advantage of the vertical integration or close affiliate relationships available to other Virginia utilities, relationships that could potentially simplify the means of sending pricing signals to affect usage patterns of residential consumers.

Many of the Cooperatives offer time-of-use and interruptible rates to larger customers, enabling commercial and industrial customers to respond and change their usage patterns and behaviors at times of high demand, but the overwhelming majority of a distribution cooperative's rate base is made up of residential retail customers. Only a minority of the Cooperatives, including Northern Neck Electric Cooperative and

² *See id.*

Mecklenburg Electric Cooperative, offer optional time-of-use rates to all rate classes, including residential. These rate structures will be viable only if the previously-discussed communications infrastructure becomes available.


Finally, the Cooperatives agree with Dominion Virginia Power's suggestion that any demand response or energy efficiency targets should take into account changes in law and regulation (such as carbon regulation), future technologies, and other unknown factors.

CONCLUSION

The Cooperatives generally want to encourage efficiency efforts, including increased demand response, and agree with the goals set forth by the General Assembly and in the Virginia Energy Plan. Recognizing the unique role of the Cooperatives in the marketplace, and building on their history of and commitment to consumer advocacy, providing service on a not-for-profit basis and at the lowest reasonable cost, and more than twenty-five years of active and successful demand reduction efforts, the Virginia Cooperatives will continue their mission of providing safe and reliable electric service to their member-owners at the lowest reasonable rates.

WHEREFORE, the Virginia Cooperatives respectfully request that the Commission carefully consider the issues raised and discussed herein in its consideration of the issues before it in this proceeding, and act accordingly.

Respectfully submitted,

By: 
Counsel for A&N Electric Cooperative,
BARC Electric Cooperative,
Community Electric Cooperative,
Central Virginia Electric Cooperative,
Craig-Botetourt Electric Cooperative,
Mecklenburg Electric Cooperative,
Northern Neck Electric Cooperative,
Northern Virginia Electric Cooperative,
Prince George Electric Cooperative,
Rappahannock Electric Cooperative,
Shenandoah Valley Electric Cooperative,
Southside Electric Cooperative,
and the
Virginia, Maryland & Delaware Association of
Electric Cooperatives

Samuel R. Brumberg
LECLAIRRYAN
4201 Dominion Boulevard Suite 200
Glen Allen, Virginia 23060
(804) 968-2981
(804) 916-7278 (fax)
samuel.brumberg@leclairryan.com

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