I. INTRODUCTION

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

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

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

Q. Please summarize your work experience and educational background.

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

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

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

A. No.

Q. What is the purpose of your testimony?

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

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

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

Steinhurst Exhibit 1, "Exhibit SELC-WB-1"	Comparison of energy efficiency ("EE") and demand response ("DR") impacts for illustrative system load duration curves
Steinhurst Exhibit 2, "Exhibit SELC-WB-2"	Comparison of bill impacts of EE and DR for illustrative commercial customers

Q. How is your testimony organized?

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

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

Q. Please summarize your recommendations.

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

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

3. Require that the Total Resource Cost (TRC) Test, the Participant Test and the Rate Impact Measure (RIM) Test be applied for the specific purposes for which they are appropriate and only for those purposes

4. Require three adjustments to the TRC test as described later in my testimony:

    a. Application of carbon costs to the cost of power

    b. Application of a 10% upward adjustment to other supply-side costs, and

    c. Application of a 10% downward adjustment to demand-side management costs.

5. Adopt, at a minimum, carbon allowance prices with a low-case allowance price of $15 per ton, a mid- or base-case allowance price of $30 per ton, and a high-case allowance price of $78 per ton (all levelized over the period 2013-2030, in 2007 dollars)

6. Correlate the Virginia statute's term "cost-effective" with the *National Action Plan for Energy Efficiency's* definition of "economic potential;" the statute's "achievable potential" with the *National Action Plan's* "maximum achievable potential;" and the statute's potential "that can realistically be accomplished" with the *National Action Plan's* term "maximum achievable" potential *except* to the extent that specific evidence demonstrates that a specific portion of the maximum achievable potential *cannot* be acquired due to a physical, legal or other practical and irremediable barrier to acquiring some particular cost-effective resource in some particular market segment *other* than budget limitations.

7. Require that utilities rely on the TRC Test (as adjusted according to this testimony) and *only* the TRC Test in cost-benefit analysis, both for program design and for field implementation

8. Require that the full costs and risks of supply-side alternatives be reflected in cost-benefit analysis

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

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

    a. Costs for programs that produce energy-related benefits should be allocated using an "energy" allocation factor (e.g. annual kWh by rate class)
    b. Costs for programs that produce capacity-related benefits should be allocated using a "capacity" allocation factor (e.g. kW of coincident peak by rate class)
    c. Costs for programs that produce a combination of energy and capacity benefits consistent with average annual supply costs should be allocated using an annual supply cost allocation factor (e.g. annual supply costs by rate class.)

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

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

A. Some of the Virginia statutes within the scope of this proceeding use both terms "energy efficiency" and "energy conservation" in various contexts. See, for example, 2007 Acts of Assembly Chapter 888 (House Bill 3068) and the identical senate bill, 2007 Acts of Assembly Chapter 933 (Senate Bill 1416), Enactment Clause 3 (". . . 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.”).

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

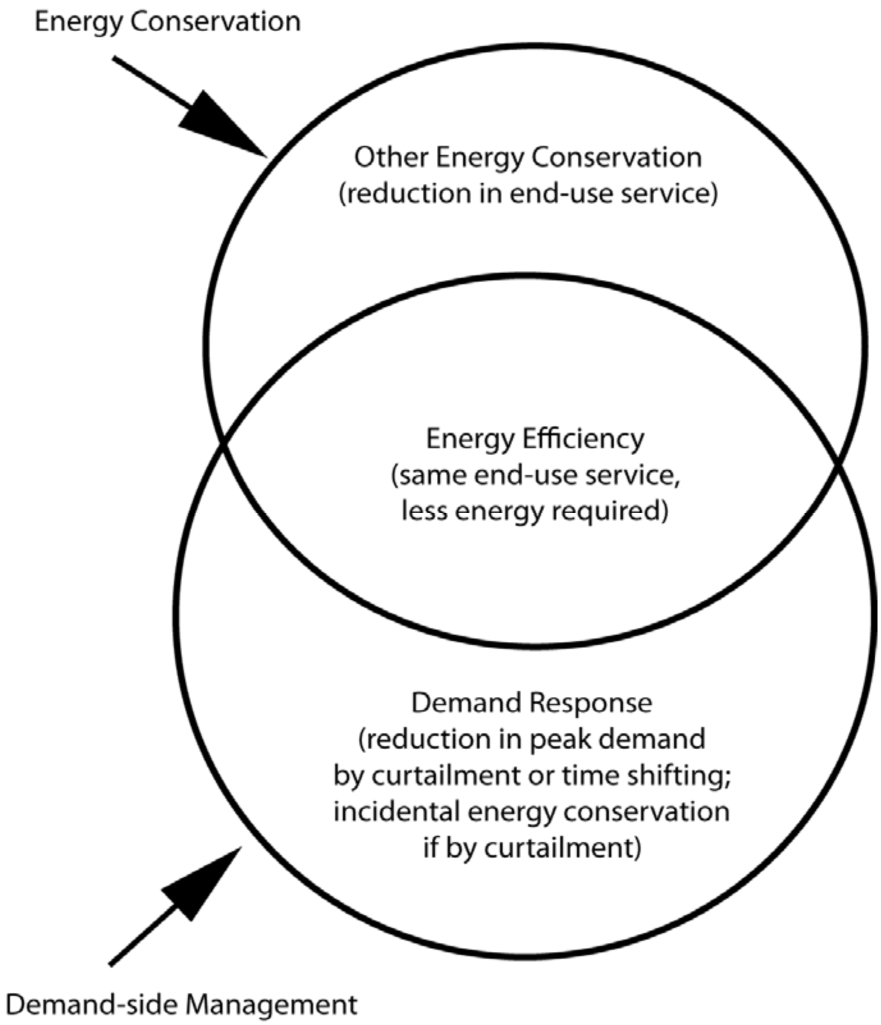

Fig. 1. Definitions of Energy Conservation and Related Terms

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

II. RESPONSES TO COMMISION QUESTIONS

Commission Question No. 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?

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

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

The costs and benefits of energy efficiency are, in some ways, qualitatively different from those of supply-side resources, and have different implications for the various parties. As a result, a number of cost-benefit tests have been devised to consider efficiency costs and benefits from different perspectives. There are several industry-recognized tests for determining whether a particular measure or program that delivers 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.

most authoritative source for the definitions of theses tests is the California PUC Standard Practice Manual, 2002 edition.[3]

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

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

- The Participant Test considers whether the customer receiving a DSM measure will save more money than her share of the measure's cost. For example, consider energy efficient light bulbs as a DSM measure. Assume a package of energy efficient light bulbs costs $10 retail and are eligible for a $5 rebate from the local utility. A customer who purchases them would pay an initial net purchase price of $5. Further assume that the bulbs will save the customer at least $5 in retail power costs over their life. Based upon those assumptions, that DSM measure would pass the Participant Test because the benefits to the Participant, i.e. savings of at least $5 in retail power costs, equal or exceed the $5 net purchase price paid by the Participant.
- The TRC Test considers whether the cash savings due to a measure are greater than the cash costs of that measure, regardless of who pays or benefits from it. Returning to the previous example, a package of efficient light bulbs that costs $10. Assume that these bulbs will enable the utility to avoid at least $15 in electricity supply costs over their life. (The amount the utility avoids exceeds the amount the bulb-buying customer avoids because the utility avoids the marginal cost of generation including new power plants, while the customer avoids the 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.

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

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

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

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

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

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[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.

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

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

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

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

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

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

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

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

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[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.

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

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

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

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

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

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

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

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

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

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.

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

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

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

Third, I recommend that the costs of DSM measures and programs be reduced by 10% prior to being used in the TRC calculation to reflect their lower risk compared to supply-side alternatives. Paralleling my first adjustment, I recommend that the Commission direct that this third adjustment be applied as a reduction to the sum of the costs of DSM, and that it be used when calculating TRC values for specific DSM 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. Stoft, 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.

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

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

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

Q. Can you give us some examples of CO_2 allowance prices used in utility resource planning as would be required under your first proposed adjustment to the TRC test?

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

The California PUC requires that regulated utility IRPs include carbon adder of \$8/ton CO2, escalating at 5% per year as of 2005.[17] The Oregon PUC has adopted a range from \$0 to about \$85/ton (levelized 2013-2030 in 2007 dollars). Other PUCs have adopted ranges from the teens to \$35–\$45/ton (also levelized 2013-2030 in 2007 dollars).[18]

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

Q. Do you have recommendations for what CO_2 allowance prices the utilities should use for planning utility energy efficiency programs and goal setting ?

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

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

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[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

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

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

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

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

Energy efficiency can also reduce the risks associated with environmental impacts, by reducing a utility's environmental impacts and helping utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO_2 regulation.[21] Of course, energy efficiency also reduces the risks associated with regulatory, liability and other costs associated with other environmental and health effects, such as those from mercury and other hazardous air pollutants, as well as the risks to the Commonwealth's economy from potential ozone non-attainment problems. Energy efficiency can improve the overall reliability of the electricity system by reducing peak demand at those times when reliability is most at risk and by slowing the rate of growth of electricity peak and energy demands and giving 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 CO_2 regulation on the industry. Available at http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf

moderating the "boom-and-bust" effect of competitive market forces on generation supply.[22]

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

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

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

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

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[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

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

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

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

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

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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.

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

4. Consumers, in the end, are more affected by the size of their electric bills (the product of rates and usage) than by the rates alone. The RIM Test does not provide any information about what happens to electric bills as a result of program implementation.
5. A strict application of the RIM Test can result in the rejection of large amounts of energy savings and the opportunity for large reductions in many customers' bills in order to avoid *de minimus* impacts on non-participants' bills. From a public policy perspective, such a trade-off is illogical and inappropriate.

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

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

The first of those issues should be addressed by:

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

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

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

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

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

> ***Some Say:***
> Customers will pay more if utilities offer energy efficiency.
> **The Fact Is:**
> - Total bills can decrease 2% to 9% over a 10-year period.
> - 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.

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

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

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

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

More particularly, the significance of the distinction primarily stems from the fact 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.

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

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

- **Capacity.** In order to ensure reliable service, the utility serving this load will own or control enough generating capacity[28] to serve the peak demand plus a reserve margin, typically in the range of 15%. The utility incurs a fixed cost for this capacity, regardless of whether it ever dispatches it to produce electric energy. Therefore, the "marginal" source of such capacity is often a gas-fired combustion turbine ("CT") plant, which has a low capital cost and a high operating cost.
- **Energy.** In order to supply the quantity of electricity that customers use in each hour the utility generates and/or purchases electric energy.[29] However, it incurs a variable cost for every MWh of electric energy generated. The cost of this energy represents the largest portion of the cost of electricity supply to most customers, which is much greater than the capacity cost. In addition, the acquisition and combustion of fuels used to generate this energy produce the vast majority of the 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.

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

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

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

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

The two customers in this example each have a peak demand of 3 kW. Customer A has annual usage of 4,500 kWh, an annual bill of $564 and a relatively low load factor 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.

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

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

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

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

A. Yes, they do.

Q. Please explain.

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

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

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

> 3. 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. . . . *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. The State Corporation Commission shall conduct a proceeding to . . . (ii) *identify the mix of programs that should be implemented in the Commonwealth to cost-effectively achieve the defined electric energy consumption reduction goal* by 2022, including but not limited to demand side management, conservation, energy efficiency, load management, real-time pricing, and consumer education . . . . The Commission shall, on or before December 15, 2007, submit its findings and recommendations to the Governor and General Assembly, which shall include recommendations for any additional legislation necessary *to implement the plan to meet the energy consumption reduction goal*. [emphasis added]

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

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

Q. What is the source of this Commission Question?

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

> 2. § 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.

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

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

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

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[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.

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

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

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

The *National Action Plan* defines technical potential, economic potential, and naturally occurring potential in a manner consistent with the way I would. I also agree with its definition of maximum achievable potential, as far as it goes. (I would clarify that "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."

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

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

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

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

Figure 2

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

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

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

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

Q. How should the Commission address that gap?

A. The problem here is what level of “program funding levels and incentives” can tell us the amount of DSM that “can realistically be accomplished.” I recommend that Commission resolve this matter by following the general practices and guidelines for integrated resource planning (“IRP”) in determining how much potential is “realistically accomplishable" (that is, how much of the "maximum achievable" potential is "achievable" in the terms of the of the *National Action Plan*).

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

Q. Why are IRP practices and guidelines relevant and appropriate to the Commission's decisions under the cited statute?

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

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

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[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.

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

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

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

A. I understand that this is now a requirement in Virginia under Va. Code §§ 56-597 through 599, with the first IRPs due by September, 2009. But my point is that the principles that underlay IRP in many jurisdictions are also an appropriate policy foundation for making the translation from "maximum achievable potential," as the *National Action Plan* puts it, to "realistically accomplishable potential" as used in Virginia statute (i.e., what policies and resource allocations should be used to determine the proper achievable potential for the Commonwealth's electric utilities). In my opinion, it would be appropriate and wise for the Commission to recognize the more than twenty-five years of IRP experience nationally in the field of power planning and, as a matter of policy, rely on those principles to resolve this issue.

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

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

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

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

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

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.

A. The Commission can best protect the public interest by following these three steps. First, as recommended elsewhere in this testimony, I recommend that utilities rely on the TRC Test (as adjusted according to this testimony) and *only* the TRC Test in cost-benefit analysis, both for program design and for field implementation. Second, I recommend that the full costs and risks of supply-side alternatives are reflected in that analysis, especially the potentially huge cost of expensive new base load plants, fossil fueled or otherwise. Third, I recommend that utility DSM targets equal the maximum achievable potential (as used in the *National Action Plan*), reducing those estimates only on evidence that there is a specific and objectively documented physical, legal or practical barrier to acquiring some particular cost-effective resource in some particular market segment other than a (desired or proposed) budget limitations. This is consistent with my explanation of how the statutory term potential “that can realistically be accomplished” should be defined by the Commission. (See my response to Commission question No. 3, above.) SELC witness Loiter provides specific numerical goal recommendations in his direct prefiled testimony.

As explained above, the Commission should keep in mind that energy efficiency and efficiency measures (1) are generally more cost effective and advance the public interest more than demand response measures and (2) ensure that energy efficiency and efficiency options are not short changed at any step in the process—from framing technical potential studies to the final program decisions and implementation—to the benefit of demand response or supply-side options.

Q. Regarding your second step, what is the source of your concern about the potential cost of expensive new base load plants, fossil fueled or otherwise?

A. DSM typically compares favorably to new generation. For example, a recent study concluded that, “these policy and programs [a package of energy efficiency policies, primarily utility DSM] can accomplish this [meeting Virginia’s needs] at a lower cost than building new generation and transmission, while at the same time 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.

Not only is DSM a better buy for ratepayers than expensive new coal plants, but costs for capital intensive base load plant have climbed rapidly in recent years. The Brattle Group, in a report prepared for the EDISON Foundation of the Edison Electric Institute concluded that:

> Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.[40]

Indeed, those trends have not abated. For example, a report issued in June of this year found that

> . . . significant cost increases have been announced for almost all other proposed coal-fired power plants in recent years. For example, the estimated per unit construction cost of Duke Energy Carolina's Cliffside Project increased by 80 percent between the summer of 2006 and June 2007. Similarly, the projected construction cost of Wisconsin Power & Light's now cancelled Nelson Dewey 3 coal plant increased by approximately 47 percent between February 2006 and September 2008. The estimated cost of AMP-Ohio's proposed Meigs County Coal Plant nearly tripled in the three years between October 2005 and October 2008.[41]

Nor are nuclear plants immune from this trend. The Toronto Star has reported that

> Energy and Infrastructure Minister George Smitherman announced on June 29 he was suspending a competitive process for the purchase of new reactors for Ontario. He cited the price tag as "billions" too high, but would not reveal the amount of the bid from AECL, deemed the only compliant proposal out of three offers.
>
> AECL's $26 billion bid was based on the construction of two 1,200-megawatt Advanced Candu Reactors, working out to $10,800 per kilowatt of power capacity.[42]

Of course, the serious lack of managerial and strategic flexibility inherent in 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.

benefits are possible makes the prospect of such cost increases even more of a concern of ratepayers. Few if any industries without captive customers would tolerate the possibility that $10 billion investment could turn into a liability with little warning.

Q. Overall, how does energy efficiency stack up against generation alternatives?

A. It is "hands down" the cheapest way to provide for Virginia's energy needs right now and for the foreseeable future. The most responsible way for the utilities to spend the ratepayers' money is spend it on EE, not new plants. The discussion above regarding the public interest and its relationship to least-cost planning supports this conclusion.

Q. Are you familiar with a recent study that demonstrates this point?

A. Yes. In December, 2007, McKinsey & Co. published a report on the costs of various measures for reducing greenhouse gas emissions in the U.S.[43] Of particular interest in this regard is Exhibit B on page xiii of that report. That exhibit shows the vast amount of emission reduction available in the U.S. from energy efficiency programs at cost that are not only less than any generation alternative, but *that are less than the cost of doing nothing at all*. (That means those measures save more than they cost.)

Commission Question No. 5. What is the potential impact of the generating electric utility's demand-side management program on economic development in the Commonwealth?

Q. Has the question of the potential impact of utility DSM programs on economic development been analyzed?

A. Yes, there have been a number of studies of this question. Typically, the conclusion is that the economic stimulus provided by utility (and non-utility) DSM programs is substantial. For example, one finding of the *Staff's Report to the State Corporation Commission in preparation for the Commission's Report to the Governor and the General Assembly* was that

> [m]ost sub-groups believed mass implementation of energy efficiency and conservation efforts would generate benefits to ratepayers and the state economy by helping to offset future increases in energy costs, provide electric system

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[43] Jon Creyts, et al., *Reducing Greenhouse Gas Emissions: How Much at What Cost?* Available at http://www.mckinsey.com/clientservice/ccsi/pdf/US_ghg_final_report.pdf

> reliability benefits, offer customers the ability to better manage their energy costs, and maintain a competitive regional economy. Additionally, effective programs could help accelerate Virginia's environmental and air quality goals while helping to reduce the costs associated with future climate change policies.[44]

From a more quantitative point of view, the ACEEE and a team of other consulting groups (including certain staff at Synapse, but not myself) estimated an Policy Case (Medium Scenario) cumulative peak load savings of 26% in 2025—19% from energy efficiency and 7% from demand response. On the energy side, the Policy Case (Medium Scenario) cumulative savings was 19% in 2025, of which about 15% was from utility DSM programs.[45] The resulting annual net consumer savings estimated from reduced electricity consumption and from lower prices, net of participant costs was about $480 million per year in 2015, and about $2.2 billion per year in 2025. The net cumulative savings to consumers was $1 billion in 2015 and about $15 billion by 2025.

The 2008 ACEEE study also presented the results of a detailed macroeconomic modeling of how those savings (and the costs of delivering them) affected Virginia's economy. The estimated net contribution to Virginia employment (full-time job equivalent) was 675 in 2015 and 9820 in 2025. This is largely driven by the fact that the electric services sector in Virginia is much less labor intensive than the energy efficiency sector. The net contribution given here reflects both sides of that equation. In addition "the increase in jobs and the changes in job mix result in a net gain to the state's wage and salary compensation" (in 2006 dollars) of $63 million per year in 2015 and $583 million per year in 2025. The net gain to the Virginia's Gross State's Product (also in 2006 dollars) was estimated to be $202 million per year in 2015 and $882 million per year in 2025.[46]

As a further example, I conducted a study that modeled, among other matters, the economic impacts of the DSM and renewable generation policies of the New England

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[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.

states as they played out during calendar years 2000 through 2004. The study showed that an investment of about $1.2 billion in energy efficiency programs resulted in a reduction in annual electricity requirements of over 3.5 million MWh. The average cost was on the order of 2.4 cents/kWh despite ten previous years of intensive DSM programs. As to the regional economy, that investment resulted in a net increase in the region's economic output of about $2 Billion (2001$), a net increase in income to workers of $694 million (2001$), and a net increase in employment of nearly 15,000 job-years.[47] Similar results have been found in numerous other studies around the country.[48]

Q. What do you conclude regarding the potential impact of the generating electric utility's demand-side management program on economic development in the Commonwealth?

A. It is clear from both the general literature and Virginia-specific studies that aggressive, well-funded utility DSM programs based on least cost planning principles and the TRC Test strongly promote a vital state economy—much more so than equivalent investment in generation or T&D. A report by the Massachusetts Office of Consumer Affairs and Business Regulation summed up the general experience in this way:

> The Division estimates that 2002 Program expenditures (plus associated participant costs) added 1,778 new jobs to the Massachusetts economy in 2002. The majority of jobs were created in the services industry (44 percent), followed by manufacturing (17 percent) retail trade (14 percent), construction (9 percent), and wholesale trade (7 percent). These new jobs added $139 million to the gross state product, including $64 million in disposable income in 2002 alone. The 1,778 jobs created in 2002 are short-term jobs, lasting the length of time needed for installation and production of the energy efficiency measures. These positive economic impacts of energy efficiency programs are consistent with results from

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[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.

> studies performed in other states, including analyses in Iowa and Illinois, as well as a combined study in New York, New Jersey and Pennsylvania.[49]

Setting aggressive DSM targets and vigorously overseeing their prompt pursuit is the best thing the Commission can do for the Commonwealth's economy at this time.

Q. Do the utility witnesses agree with you on this point?

A. Not entirely. For example, APCO witness Castle admits "overall expenditures on electricity will be lower in the longer term than they otherwise would have been through the use of traditional supply options." However, he also claims that while jobs will be created through DSM program spending, the costs of those programs to consumers will reduce spending.[50] This overlooks the relative magnitude of those (and other related) influences. The studies I reviewed above (and all properly conducted studies of such effects) net out the suppressive effects that concern him and report the net benefits. Dominion witness Venable does not appear to express a firm opinion either way.[51]

Commission Question No. 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"?

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[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.

Q. What is your recommendation for 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. I recommend the Commission allocate utility DSM program costs among all rate classes. The specific class allocators could be determined in various ways. I have not reviewed the Commission's specific rate design practices, but can give the reasons for my recommendation and offer a general explanation of my view of class cost allocators for DSM.

Q. Please do so.

A. DSM is a resource that provides system-wide benefits in addition to any benefits it provides to program participants or, even, to the specific rate classes to which the program participants belong. For any DSM measure or program, the fact that it passes the TRC Test is an affirmation of system wide benefit on its own. In addition, DSM measures and programs that are cost-effective under the TRC Test also deliver broad, system-wide benefits through reduced external costs, by reducing market clearing prices for electricity, ancillary services and natural gas, and, perhaps most importantly (by moving the clearing price "down the supply curve"), the capital costs and financial risks entailed in any avoidable future capacity costs for generation or T&D facilities (aside from customer-specific facilities).

In other words, while DSM program participants who reduce the quantity of electric energy they consume see a benefit on their bills, to the extent that DSM measures reduce the need for new capacity, the costs of which are recovered from everyone, there is a system wide benefit. For that reason, alone, it is appropriate to allocate DSM program costs among all rate classes. The Commission should also take note of the fact that the financial, regulatory and operational risks avoided by a reduced need for new capacity, as well as a reduced reliance on volatile fuel prices, accrue to all ratepayers through less volatility and uncertainty in retail rates and, even more broadly, lower the cost of capital that can accrue to utilities that avoid those risks. These risk benefits are above and beyond those generally accounted for in the TRC Test but would be recognized, at least in part, by the 10% risk adjustment I recommend be required in the application of the TRC Test.

As explained by APCO witness Thomas, the choice of an allocation factor will depend upon the type of the system-wide benefits, in a manner equivalent to the allocation of supply resource costs on the basis of "cost causation."[52] However, I disagree with his suggestion that *all* the costs of energy efficiency programs be allocated using energy factors. The choices of allocation factors according to classification of system-wide benefits should include the following:

1. Costs for programs that produce energy-related benefits should be allocated using an "energy" allocation factor (e.g. annual kWh by rate class)
2. Costs for programs that produce capacity-related benefits should be allocated using a "capacity" allocation factor (e.g. kW of coincident peak by rate class)
3. Costs for programs that produce a combination of energy and capacity benefits consistent with average annual supply costs should be allocated using an annual supply cost allocation factor (e.g. annual supply costs by rate class).

Q. You have referred to the risk-avoidance benefits of utility DSM programs. Can you explain those benefits?

A. I have done so earlier in this testimony along with my reasons for the adjustments I recommend the Commission make to the TRC Test.

Q. Do you have any other observations on this issue?

A. Yes. Dominion proposes that costs be allocated jurisdictionally.[53] This statement apparently means that costs of DSM measures installed in the Company's Virginia jurisdictional territory would be allocated to its Virginia cost of service. Among the reasons given for this is that "[t]he reductions to energy usage and demand caused by DSM programs will affect the jurisdictional allocation factors." This seems reasonable on its face, but the Commission may wish to assure itself that the allocation factors give Virginia full credit for any power cost savings to the parent company and its affiliates. 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.

prevent the flow through to the jurisdictional customers of all the power supply savings accrued as a result of DSM in Virginia.

Commission Question No. 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?"

Q. What is the essential, or threshold, policy issue underlying Commission Question 9?

A. The essential, or threshold, policy issue underlying Commission question 9 is whether it would be in the public interest for the Commonwealth to permit certain customers to be exempt from participating in or paying for utility demand-side management programs or both. That is a threshold question because, if the answer is "no," then the request for information on class cost responsibility methods used in other jurisdictions that allow such exemptions may be rendered moot.

The question of whether it would be in the public interest for the Commonwealth to permit certain customers to be exempt from paying for utility demand- side management programs seems to contemplate a re-examination of the current Virginia policy regarding such exemptions. That current policy, established in House Bill 2506 passed by the 2009 General Assembly, mandates exemptions for very large use customers, those whose demand exceeds 10 MW, and allows exemptions for general service customers whose demand exceeds 500 kW subject to criteria the Commission must establish by November 2009.

Q. Would it be in the public interest for the Commonwealth to exempt certain customers from paying any electric utility demand-side management program costs automatically, or as a matter of general policy?

A. No. It would not be in the public interest for the Commonwealth to exempt certain customers from paying any utility demand- side management program costs automatically or as a matter of general policy. Instead, the general policy should be to require utilities to allocate their DSM program costs among all customers just as they allocate their supply costs among all customers. If exemptions are allowed, they should not be automatic for any category of customers. Instead exemptions should only be granted to a very few customers who submit requests demonstrating efficiency achievements at least equal to those being achieved under utility programs.

It would not be in the public interest for the Commonwealth to exempt certain customers from paying any utility demand-side management program costs as a matter of general policy because this results in rates that are not reasonable. The customers who are exempted will still be acquiring electricity, and thus will still be receiving the system benefits of the utility's DSM programs, but will not be paying their share of the costs of the underlying programs. In order to appreciate this inequity one must recognize that, as I discuss above in answering Commission question 8, utility DSM programs are a resource that provide system-wide comparable to supply resources. In fact, as I described earlier, the fact that DSM programs provide benefits to all customers over time provides the policy and ratemaking justification for allowing utilities to recover the costs of those DSM programs in rates. When DSM is properly viewed as a cost-effective resource providing system benefits, it is clear that a particular customer, whether or not that customer has reduced his or her energy use or peak demand, should not be exempt from paying for any DSM program costs. As long as the exempt customer is still acquiring electricity, that customer is still receiving the system benefits of the utility DSM programs year after year over the long term.

There is substantial potential for inequity in rates under the current Virginia policy regarding exemptions. The customers eligible for exemptions allowed under this policy represent a significant portion of the annual electricity used in Virginia. For example, Mr. Thomas estimates that these two categories of customers account for over 36% of the annual retail electricity sales of Appalachian Power Company in Virginia.[54]

Moreover, allowing a customer to be exempt is even *less* in the public interest when that customer does *not* reduce his or her energy use and peak demand to the full extent cost effective under the TRC test, because that failure imposes excess, unnecessary and economically inefficient system-wide costs on the utility and all other ratepayers. To the extent that ratemaking and rate design policies results in those excess system-wide

[54] Thomas testimony at 10.

costs being borne by all or some subset of customers, a similar and additional inequity in rates is created for the long-term, but in opposite direction. As a result, exempt customers of this type not only benefit from system-wide savings created and paid for by others, but also pay less than their share of the system-wide costs that they create.

This discussion has focused on the cost of service aspects of system-wide benefits. Of course, the same argument applies to all system-wide benefits. One such system-wide benefit of critical importance is risk reduction for the utility. I discussed that point under Commission question No. 8, above, and explain the risk-avoidance benefits of utility DSM programs further below under "Other Issues."

Q. Might it be in the public interest for the Commonwealth to exempt certain customers from paying a portion of utility DSM costs to reflect self-financed expenditures on efficiency improvements that meet specific criteria?

A. Under certain conditions, it might be. It may be in the public interest for the Commonwealth to allow certain customers to exempt certain customers from paying a portion of the utility DSM costs charged to them to reflect self-financed expenditures on efficiency improvements that meet specific criteria. Under this approach, a customer is exempted from paying a portion of the DSM costs it would otherwise pay, e.g., the DSM program surcharge applied to its annual usage, equal to the amount it has spent on energy efficiency measures within its facility. This approach has been referred to as "banking" in some states and "opt out" in others. In fact, this is effectively the approach that has been approved in North Carolina.[55] The minimum requirements for this approach to be in the public interest lies in selecting criteria that require customers who apply for this exemption to demonstrate, subject to independent verification, that they have used their own funds to install efficiency measures that are cost-effective to the same extent and according to the same avoided cost assumptions and cost-effectiveness tests as those used by their utility.

Q. Why is it not in the public interest to simply exempt certain customers from paying all of their utility DSM costs after a one-time demonstration of self-financing of expenditures on efficiency improvements?

[55] N.C. Gen. Stat. § 62-133.8(f)

A. Exempting certain customers from paying all of the utility DSM costs otherwise charged to them after a one-time demonstration of self-financing of expenditures on efficiency improvements will lead to unreasonable rates. Utilities incur DSM program costs year after year in order to achieve all cost-effective efficiency reductions. While it may be appropriate to exempt a customer from paying a portion of the DSM costs it would otherwise pay equal to the amount it has spent on energy efficiency measures within its facility, the fact remains that the customer is still acquiring electricity and still receiving the benefits of the utility DSM programs. Moreover, if self-financing is to be allowed, then customers interested in self-financing must continue self-financing of efficiency expenditures until it has implemented all cost-effective measures at its site.

Q. What states that exempt certain customers from paying a portion of utility DSM costs to reflect self-financed expenditures on efficiency improvements do you consider to have model policies?

A. Oregon, New Mexico, and Utah, for example, all limit the amount of the credit or offset a customer can claim to some capped value which is less than 100% of the amount self-financed.[56]

III. OTHER ISSUES

Q. Do you have any other recommendations in regard to energy efficiency programs?

A. Yes, I have two. The first highlights the importance of avoiding the creation of lost opportunities in the course of delivering utility energy efficiency programs and explains some of the standards that the Commission should impose to prevent that outcome. The second relates to provision of energy efficiency services to certain hard-to-reach customer groups and explains some of the standards that the Commission should impose to ensure equitable treatment of those customers and to avoid losing out on the efficiency savings available in their homes and businesses.

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.

A. The Commission should prohibit the creation of lost opportunities and cream skimming in the design and implementation of utility DSM programs. This recommendation is an essential consideration that flows from the duty to assure least cost service.

Q. Please explain those terms and why you make this recommendation.

A. Utility energy efficiency programs, as for any other utility expenditure or investment, should be prudently managed and deliver least cost service. Two important policies are necessary to ensure that outcome. First, utility energy efficiency programs should be designed and implemented to minimize "lost opportunities." Lost opportunities occur when efficiency measures are not installed when it is most cost-effective to do so (e.g., the construction of a new building or facility, building renovations, and the purchase of new appliances or equipment). Second, programs should be designed and implemented to minimize "cream skimming." Cream skimming occurs when only the most cost-effective efficiency measures are installed, even though additional, higher-cost measures would be cost effective. Cream skimming can lead to lost opportunities, because revisiting a customer to install the remaining measures may involve prohibitive transaction costs.

While this is not a program design proceeding, I bring this issue to the Commission’s attention because, in my experience, the decision rules adopted by utilities often arbitrarily or erroneously create lost opportunities or base their designs on cream skimming approaches. Some utilities in other jurisdictions have arbitrarily limited the number of compact fluorescent bulbs installed in a given residence, even if there are additional change outs that would have been cost-effective. Once the overhead has been spent to enroll a customer in an audit or custom measure program or otherwise, deliberately omitting any cost effective measure prevents least cost resource acquisition and is, therefore, imprudent management. Lost opportunity measures must be designed, approved and deployed as soon as possible, and then the utility can push for maximum (empirically supported) market penetration of that measure. This is critical because if the utilities wait several years to implement these measures, critical opportunities will be lost.

The Commission would be wise to take the precaution of explicitly requiring that utility energy efficiency programs be designed and delivered in a manner that prevents cream skimming or the creation of lost opportunities. I also recommend that the Commission require that utility energy efficiency programs (1) adhere to comprehensive approaches that improve energy efficiency of entire buildings or industrial processes, rather then just address single measures or technologies, and (2) include a full menu of services, including incentives, marketing, training, technical assistance, and education on a number of end use applications (such as lighting, appliances, HVAC systems, and improvements to the building envelope).

Q. What is your second additional recommendation?

A. Equity demands proper treatment of hard-to-reach customers, including those on limited incomes, small businesses, and others. These customers face higher and added barriers to implementing DSM on their own or participating in DSM programs. Specifically, the Commission should require that utility energy efficiency programs (or additional, special programs as needed) be designed and implemented so as to ensure that hard-to-reach customers' needs are met in ways the work for them, not just the average customer. Further, as pointed out by Dominion witness Venable[57],

> . . . the Second Enactment Clause of Chapter 603 of the 2008 Acts of Assembly ("House Bill 1523"), which created Chapter 24 of Title 56 of the Va. Code, states:
>
> > That as part of its 2009 integrated resource plan developed pursuant to this act, each electric utility shall assess governmental, nonprofit, and utility programs in its service territory to assist low income residential customers with energy costs and shall examine, in cooperation with relevant governmental, nonprofit, and private sector stakeholders, options for making any needed changes to such programs. [emphasis added.]

Q. Please explain why you make that recommendation.

A. In my experience, some utility program designs and implementation strategies indicate a lack of sensitivity to this requirement and lead me to spell out in some detail here the policy on hard-to-reach customers, which I recommend the Commission adopt and require utilities to use in their energy efficiency programs. The Commission should also establish goals that are based on potential studies not tainted with such errors.

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[57] Venable testimony at 9.

Q. What do you mean by "hard-to-reach" customers?

A. By hard-to-reach customers I mean:

1. Residential electricity users who rent their residences from persons other than kin (defined in a manner appropriate to Virginia law and society), trusts operated by and for the benefit of the users, or the users' legal guardians;
2. Commercial electricity users who rent their business property from persons other than the users' owners, parent companies, subsidiaries of their parent companies, their own subsidiaries, or trusts operated by and for the benefit of the same;
3. Residential or commercial electricity users who traditionally fail to engage in energy efficiency or demand response programs because of one or more severe barriers beyond those experienced by average residential or commercial customers in a utility's service area.

By "barrier," I mean any physical or non-physical necessity, obligation, condition, constraint, or requisite that obstructs or impedes electricity user participation in energy efficiency or demand response programs. Barriers may include but are not limited to language, physical or mental disability, educational attainment, utility meter type, economic status, property status, or geography.

Q. What policy do you recommend to the Commission in regard to utility energy efficiency programs for hard-to-reach customers?

A. I recommend that the Commission policy be that utilities are required to address programs for limited-income customers and other hard-to-reach customers so as to assure proportionate energy efficiency programs are deployed in these customer groups despite higher barriers to energy efficiency investments. The Commission may wish to allow programs targeted to low-income or hard-to-reach customers to meet lower threshold cost-effectiveness results than other programs or be enhanced in other ways to ensure that those customers are not left out.

Q. Does this complete your testimony?

A. Yes, at this time.