Subgroup 3 Report:

DEMAND/PEAK REDUCTION

October 1, 2007

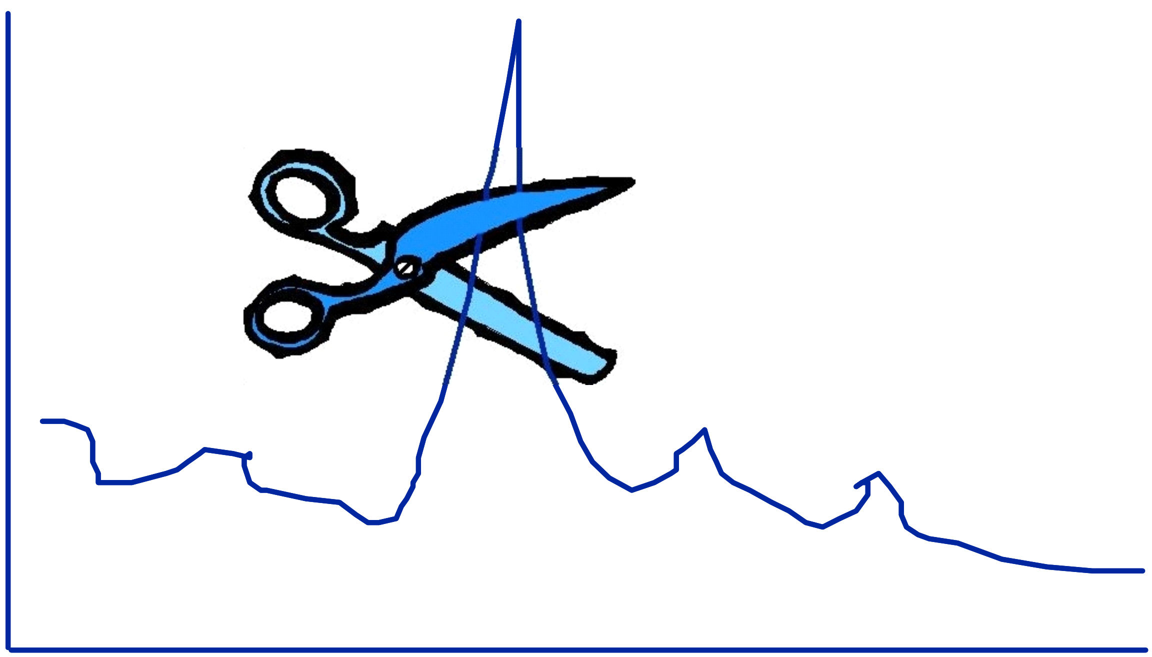

TABLE OF CONTENTS

Preface

This report was prepared by Subgroup 3 of the SCC Workgroup. As seen below, the Subgroup had a good representation from all categories of stakeholders in the demand management area. The membership included the following individuals:

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Our objective was to develop recommendations for peak demand management actions that would benefit Virginia's electricity users. We have assessed the situation in Virginia and uncovered both short- and long-run opportunities for demand response and peak demand reduction.

We appreciate the opportunity to contribute to this important endeavor.

Executive Summary

- **The time has come to overcome missed opportunities.**

The importance of reducing peak demand has long been recognized by the Virginia General Assembly and the State Corporation Commission (SCC). However, State policymakers have failed to initiate comprehensive policies to address this challenge even though they recognized the important benefits to ratepayers more than 30 years ago. Now, construction of significant additional generation and transmission capacity is planned for the near future so a new opportunity exist to properly recognize demand reduction as an alternative to new facilities.

- **Virginia should proceed on an urgent basis to set a demand reduction goal (in MW) in addition to the electricity use reduction goal within a framework that addresses incentives for utilities to regard investment in demand response resources on par with investment in supply-side resources.**

The 2007 legislation established a goal of reducing total energy use (MWh) by 10% of 2006 levels over the next 15 years. The Subgroup strongly recommends the establishment of a goal for demand reduction (in MW) by a specified time separate from the MWh goal set forth in the legislation. The SCC should periodically review utility performance in meeting the goal and the continued appropriateness of the specified goal. Utilities should have flexibility in cost-effectively achieving the goal, with incentives awarded based on real results.

- **Peak demand reduction programs (demand response) will provide numerous benefits to Virginia electric customers.**

These benefits will include substantial customer financial benefits and electric reliability benefits. Individual customers can receive substantial savings on their energy bills and incentive payments by adjusting their electric demand in response to time-of-use electric rates and incentive-based programs. In addition, demand response programs serve to reduce wholesale market prices because such programs avert the need to use the most costly-to-run power plants during periods of otherwise high demand – driving generation costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained and targeted demand response lowers the need to build new generating, transmission, and distribution system capacity. In addition, reliability benefits accrue because demand response lowers the likelihood and consequences of forced outages on the electric grid.

- **There is an urgent need to achieve the maximum practical demand reduction potential in Virginia.**

Virginia’s electricity customers have enjoyed lower than average electricity prices over the last several years. This has contributed to the limited interest in energy efficiency and demand reduction in the state. However, the state’s power companies are now facing a period of rising electricity costs from a combination of rising consumption of electricity requiring new investment in supply infrastructure, projected increases in equipment and fuel costs and the potential for additional environmental restrictions on power production. The elimination of price caps and renegotiation of fuel price adjustments will translate these rising costs into higher electricity prices to customers in the years ahead.

Further, the use of electricity in the Commonwealth is not uniform all year long, but varies during the year. In Virginia, peaks in electricity usage and the highest electricity costs occur during the coldest days of the winter and the hottest days of the summer. Summer peak demand, for example, can be two to two and a half times average demand levels. The capacity of the electric system must be designed to reliably meet those peak needs during those times. The summer peak is especially significant since the carrying capacity of the transmission and distribution system is lowest during hot weather. Thus the system must be designed with significant added capacity that is actually needed only during about 100 hours in the summer and winter.

During periods of peak demand, the wholesale price of electricity purchased by Virginia in the regional PJM electricity market has at times reached the price cap of $1,000/MWh (August 2007) – more than 17 times the average price of $57/MWh. Even though these extreme costs occur during a limited number of hours, they are a significant part of annual power costs to customers.

- **Virginia lags most states in implementing effective demand response programs.**

Current peak reduction programs in Virginia include some time based rates, some participation by very large customers in PJM peak reduction programs, a critical peak pricing program for very large commercial and industrial customers and some residential control systems for demand response. In addition to relatively low average electricity prices, Virginia's rate structure spreads the high peak costs over many hours. Thus few customers have been exposed to the very high peak costs.

As a result of low average rates, current rate design and low levels of promotion for these programs, current program investment and customer participation in Virginia significantly lags the leaders among states.

Reducing electricity use during periods of very high demand levels may be less costly and more reliable than adding to expensive infrastructure and relying on high-cost fuels. As Virginia faces rising demand for electricity and rising costs to produce and deliver at those peak times, demand reduction programs make sense and should be encouraged.

- **Regional, State, and utility demand response programs are all needed to achieve effective demand response.**

Programs at all three levels are needed to derive maximum current and future benefits. The SCC, utilities, PJM and Curtailment Service Providers should make a priority of working to resolve outstanding concerns regarding existing PJM DR programs.

- **Commence an aggressive effort to implement programs that reduce predictable peaks and defer the need for additional capacity.**

PJM programs do not provide appropriate incentives to reduce future growth of the peak demand. Aggressive State and/or utility programs are needed to take advantage of all opportunities to reduce future costs of supply. Illustrative examples of the magnitude of potential benefits are provided in the Subgroup's report. Absent any demand-side programs, Virginia expects to have to add over 5,000 MW of generation capacity over the next ten years. Time is of the essence.

- **Continuing efforts are needed**

We recommend continuation of the Workgroup as a Virginia Energy Collaborative to develop a Virginia Energy Action Plan, to continue to identify and mitigate impediments, and to update the Action Plan as needed. The Subgroup believes that the level of effort that it will take to implement this Action Plan will require additional resources within the SCC.

Summary of Findings and Conclusions

A. Background

The importance of reducing peak demand has long been recognized by the Virginia General Assembly and the State Corporation Commission (SCC). However, State policymakers have failed to initiate comprehensive policies to address this challenge even though they recognized the important benefits to ratepayers more than 30 years ago. The time has come to address this problem.

In a 1976 report required by the General Assembly, the authors emphasized that "the reduction of peak demand [is] a major goal." The report further stressed that "[i]n the long run, the reduction of peak demand is the one area where savings to the ratepayer can be accomplished and it must be followed up." More recently, this issue was addressed in a 1991 staff report to the SCC, in a 2006 SCC proceeding on time-of-use rates and advanced metering, and in legislation enacted by the General Assembly in 2007.

However, the picture of demand response (DR) in Virginia during the past three decades is one of missed opportunities. Although numerous states initiated aggressive and effective demand response programs in the 1970s, 1980s, and 1990s, Virginia continues to lag far behind.

However, the need for action is more pressing now than ever. The multiple challenges of rapidly escalating fuel and electricity prices, global climate change, deteriorating electric reliability in the mid-Atlantic region, and energy security risks provide a clarion call for prompt action.

Moreover, new opportunities are now available to harness the potential for reductions in peak demand. These new opportunities are the result of: (1) development of new policies in the PJM[1] market requiring the treatment of demand response on a par with supply-side options; (2) advances in telecommunications that allow for real-time communication among wholesale electric suppliers, retail suppliers, and customers; and (3) improvements in the affordability and functionality of demand response technology.

It is essential for the SCC to take advantage of new legislative authority granted in 2007 (as well as preexisting legislation enacted in 1976 requiring conservation of capital and energy resources) to meet these pressing needs and harness the new opportunities. The time is now to implement critical regulatory reforms that will spur reductions in peak load demand. The 2007 legislation provides another window of opportunity for action in the Commonwealth of Virginia to promote demand side management. Virginia ratepayers and the State's economy and environment will suffer if this opportunity is squandered.

[1] PJM is the grid operator for the wholesale market in the mid-Atlantic Region (the PJM Interconnection)

B. About Demand Response (DR)

Programs designed to reduce customer demand (MW) have recently been termed “demand response.” In the past they were often referred to as “load management.” The definition and benefits of demand response (DR) were summarized well in a report issued by the Department of Energy in February 2006[2]. This report emphasized that:

> Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.
>
> • *Price-based demand response* such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high.
>
> • *Incentive-based demand response programs* pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.
>
> * * * * * * * * * *
>
> States should consider aggressive implementation of price-based demand response for retail customers as a high priority, as suggested by EPACT. Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers. Price-based demand response cannot be achieved immediately for all customers. Conventional metering and billing systems for most customers are not adequate for charging time-varying rates and most customers are not used to making electricity decisions on a daily or hourly basis. The transformation to time-varying retail rates will not happen quickly. Consequently, fostering demand response through incentive-based programs will help improve efficiency and reliability while price-based demand response grows.
>
> **The Benefits of Demand Response**
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> The most important benefit of demand response is improved resource-efficiency of electricity production due to closer alignment between customers’ electricity prices and the value they place on electricity. This increased efficiency creates a variety of benefits, which fall into four groups:

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[2] U.S. DOE, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, February 2006 http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

• *Participant financial benefits* are the bill savings and incentive payments earned by customers that adjust their electricity demand in response to time-varying electricity rates or incentive-based programs.

• *Market-wide financial benefits* are the lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained demand response lowers aggregate system capacity requirements, allowing load-serving entities (utilities and other retail suppliers) to purchase or build less new capacity. Eventually these savings may be passed onto most retail customers as bill savings.

• *Reliability benefits* are the operational security and adequacy savings that result because demand response lowers the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.

• *Market performance benefits* refer to demand response's value in mitigating suppliers' ability to exercise market power by raising power prices significantly above production costs.

The financial benefits to the participants, particularly the larger ones, cannot be overemphasized. They create new opportunities for energy efficiency or other investments. Examples include facility enhancements, such as continuous commissioning, building control system upgrades, purchases of renewable energy certificates or carbon credits, as well as productivity improvements for industrial customers.

Demand response is generally focused on reducing peak demands of the utility, not necessarily the individual end-use customer's peak demands.

A broad range of demand response technologies is available and continues to evolve with a number of new and enhanced technologies appearing on the market or in development. Included among the options are switches for control of specific devices, remotely controllable thermostats, energy management systems with automatic demand control, computer-controlled load management systems, improved communications technologies (both customer premise and wide-area networks), improved metering technologies with built-in demand-response functionality, Internet-controlled systems and integration of other subsystems with on-site generation and/or renewable energy sources. When developing a demand response program, it should be flexible enough to accommodate a number of approaches and technologies appropriate for a variety of customers and needs and electrical configurations. An effective program should take advantage of developing technologies and should be as broadly compatible across devices and systems as possible to maximize the useful life of equipment and to maintain options for expanding the scale of existing programs.

One of the emerging capabilities for enabling demand management is the advent of advanced meters and the concept of an Advanced Metering Infrastructure (AMI). AMI is not a specific technology; rather it is an infrastructure which has at its core a bi-directional network with advanced meters. The actual capabilities depend on the selection of specific equipment from technology suppliers. In general, the primary benefit of creating an AMI is the ability to quickly process large amounts of pricing and usage data and make such data available to both the customers and the service providers. AMI not only offers opportunities for sophisticated load management measures behind the meter, but it also provides a platform for potential benefits for utility operations in areas such as remote service connects/disconnects, outage management, theft detection and remote load control.

AMI is not a prerequisite for demand response. Rather, it should be viewed as a significant option to enhance opportunities for communicating prices to customers in real- or near-real time, accelerating measurement and verification of demand changes, and facilitating faster data processing and settlement. Eventually, AMI may become a part of a "smart grid"[3] -- a network tying together and coordinating supply-side resources with customer processes.

Meanwhile, demand response program design should include a thorough evaluation of AMI capabilities relative to other alternatives and should take advantage of the range of technologies available to the extent that they can be integrated into an overall coordinated program and are designed to be cost-effective. Interoperability among devices should be one of the focal points of such an evaluation; this is important to ensure that the utility retains the flexibility to use multiple technology vendors.

A number of pricing approaches exist to encourage reduction in electrical load during times of peak demand which are generally designed to either approximately or very precisely reflect variations in the cost of producing electricity over time. Dynamic pricing methodologies or rebates and incentive payments are effective tools for encouraging customers to voluntarily reduce load during times of peak demand or to shift load to off-peak periods. Rates can be designed so that long- or short-term variations in pricing can be accommodated. Each of these approaches (or a combination) can be used to support a demand response program.

Utilities are well positioned to develop, implement, and administer demand side management programs that involve demand response because of their substantial expertise in the technical aspects of load management, specific knowledge of their electrical grid systems, relationships with their customers, and existing administrative mechanisms. In addition, the growing number of private sector firms that provide specific load curtailment and related services constitute a very important resource for enhancing the effectiveness of and expanding the reach of demand response programs.

Energy efficiency and conservation programs that involve initiatives such as consumer education, rebates and incentives to encourage the adoption of higher efficiency equipment and market support functions are best administered through a non-utility third party, such as a state agency or private sector organization, in order to maximize the consistency and availability of program offerings. In comparison to demand response

[3] Referenced in national energy legislation currently under consideration by the U.S. Congress.

programs, energy conservation programs do not depend on system-specific events and knowledge.

Coordinating various programs available to customers avoids confusion and potential conflict among the various programs and also allows customers to select the options that make best sense for them. Good coordination among program offerings makes it possible to develop complementary (rather than conflicting) programs and to take advantage of opportunities for demand response that arise with new residential and non-residential development activities.

C. Virginia's Situation

Virginia's electricity customers have enjoyed lower than average electricity prices over the last several years. This has contributed to the limited interest in energy efficiency and demand reduction in the state. However, the state's power companies are now facing a period of rising electricity costs from a combination of rising consumption of electricity requiring new investment in supply and transmission infrastructure, projected increases in fuel costs and the potential for additional environmental restrictions on power production. The elimination of price caps and renegotiation of fuel price adjustments will translate these rising costs into higher electricity prices to customers in the years ahead.

Further, the use of electricity in the state is not uniform all year long, but varies during the year. In Virginia, peaks in electricity usage and the highest electricity costs occur during the hottest days of the summer and the coldest days of winter. Summer peak demand, for example, can be two to two and a half times average demand levels. The capacity of the electric system must be designed to reliably meet those peak needs during those times. The summer peak is especially significant since the carrying capacity of the transmission and distribution system is lowest during hot weather. Thus the system must be designed with significant added capacity that is actually needed only during about 100 hours in the summer and winter.

In addition, electricity is very expensive to produce during peak times. High-cost gas and less efficient plants are brought into service to fill the high demand. The cost to buy a kWh of electricity during peak hours can be almost 20 times the cost at other times, rising to $1.00 per kWh in a state where the average electric rate is only about $.07. Even though these extreme costs occur during a limited number of hours, they are a significant part of annual power costs to customers.

Finally, peak demand in Virginia is expected to grow at about 1.9% per year in the decade ahead, leading to a need for yet additional investment in electric supply and delivery capacity and more use of expensive peaking fuels, driving costs still higher in the years ahead.

Current peak reduction programs in Virginia include some time-based rates, some participation by very large customers in PJM peak reduction programs, a Critical Peak Pricing program for some very large commercial and industrial customers, and some residential demand control systems. However, in addition to relatively low average electricity prices, Virginia's rate structure spreads the high peak costs over many hours. Thus few customers have been exposed to the very high peak costs.

As a result of low average rates, current rate design and low levels of promotion for these programs, current program investment and customer participation in Virginia significantly lags the leaders among the states.

Reducing electricity use during periods of very high demand levels may be far less costly and more reliable than adding to expensive infrastructure and relying on high-cost fuels. As Virginia faces rising demand for electricity and rising costs to produce and deliver at those peak times, demand reduction programs make sense and should be encouraged.

D. Impediments

Historically, the focus on the utility industry in Virginia has been on supply-side solutions to address peak demand rather than on demand-side approaches. Even where legislation has encouraged demand-side management, there were no specific goals established nor was there follow-up action to track and report actual progress. As a result, expensive generating plants and transmission lines have been built and continue to be planned to meet peak loads during limited hours of the year, including critical peak capacity that is effectively needed for less than 100 hours annually.

A variety of factors have contributed to the focus on supply-side approaches in Virginia and other states. These factors include:

- cost recovery approaches that have provided a disincentive for utilities to pursue demand response programs;
- institutional and infrastructure barriers;
- lack of consumer awareness;
- limited rate design options;
- barriers to providing demand response by third parties;
- measurement and verification challenges; and
- the lack of consensus procedures for the determination of cost-effective programs.

Institutional and infrastructure barriers have posed a particular problem. Until this year, there had been no mechanism for valuing demand reduction on an equivalent basis to supply to meet critical peak demand in the wholesale electricity market. PJM has initiated a demand response program intended to accomplish this, but there are concerns by utility stakeholders regarding this program.

Necessary metering and/or other enabling equipment supporting real-time DR has not been in place for the majority of customers. The absence of consensus standards for mass-market energy management equipment has created impediments to residential and small business customer deployment.

Except for interruptible programs for a small number of large commercial and industrial customers, most demand-side management in Virginia has used TOU rates (some with a demand charge) based on long periods (of more than 2000 hours per year) – severely limiting their value. For example, under Dominion’s Schedule 1S for residential customers, the on-peak period is 11 hours daily all summer and 8 hours all winter (five days a week) whereas the critical congestion periods amount to less than a hundred hours a year. Thus, these rate designs do not provide demand response on a real-time or near real-time basis that could provide incentives for more targeted demand reductions during critical peak periods. Moreover, even where time-of-use (TOU) rates are available, such as for Virginia Power customers, they are largely unaware of them. Even when customers request information on them, they are frequently told by company phone center employees that the rates are either not available or that they are not eligible for them.

None of the impediments to demand response in Virginia are insurmountable. In fact, many other states have moved ahead rapidly to overcome these challenges and to deliver substantial levels of real-time demand response.

E. Programs/Action Recommendations

The Subgroup reviewed the status of load management and demand-side management programs in Virginia and developed recommendations to reduce the impediments to expansion of them. These included a lack of perceived need, inadequate cost recovery and profitability, institutional and infrastructure barriers, fragmentation in the industry and regulatory oversight, low valuation of demand response, and lack of customer awareness. New industry developments now allow demand response programs specifically during periods of high wholesale level prices, as distinct from historical programs involving time-of-use programs during full days, five day a week all year.

- **Establish quantified goals for DR and track them on annual basis**

The Subgroup recommends the establishment of a quantified goal for demand reduction (MW) by a specified time separate from the consumption (MWh) goal set forth in the 2007 legislation. The SCC should periodically review utility performance and the continued appropriateness of the specified goal. Utilities should have flexibility in cost-effectively achieving the goal, with incentives awarded based on real results. The SCC should be required to submit an annual report to the General Assembly for DR, consumption reduction and conservation. In addition, the utilities should be required to submit annual reports on demand response and demand management that are subject to SCC approval, including performance results for incentives tracking.

- **Establish policies for utility cost recovery and profit to result in DR having at least equivalent value as those of supply side resources**

Utilities should be allowed full cost recovery, including lost revenue recovery, plus appropriate incentives for successful deployment of cost-effective DR programs. DR valuation should be at least equivalent to supply-side resources. Consideration should be given to “decoupling” the direct correlation between utility revenues and total electricity consumption. The societal benefits of DR are currently explicitly excluded from the valuation of demand-side resources. We recommend that this policy be reevaluated. Cost recovery for planning and executing demand response programs should begin on January 1, 2008, rather than wait for the removal of capped rates.

- **Implement a consumer education program**

Virginia also should encourage participation in DR programs for all classes of customers, including providing education and incentives. Specifically, establishment and funding of the Customer Education Program recommended by the Information Subgroup should have a very high priority. This should include achieving broad consumer awareness of the Virginia State Energy Plan and the need for their individual actions to participate in it.

- **Establish policies for Virginia's participation in PJM wholesale markets and the role of Curtailment Service Providers**

PJM is implementing new programs for DR. Utilities and CSPs are deploying them in most states within the footprint of the PJM power market. The SCC should encourage and implement procedures and policies to foster these and other complementary programs throughout Virginia. The SCC, utilities, PJM and CSPs should make a priority of working to resolve outstanding concerns regarding existing PJM DR programs in order for those programs and new ones that may be created to realize their full potential. Consideration should be given to allowing utilities to include MWs delivered by the CSPs in their territory as counting toward their DR goals.

- **Begin evaluation of the potential and benefits of advanced metering infrastructure**

The SCC also should begin evaluation of deployment of advanced meters, advanced metering infrastructure (AMI), and the capabilities that would support the ultimate creation of a "smart grid".

- **Establish policies and procedures to improve the use of otherwise idle generation equipment during critical peak times**

Policies should be evaluated for implementation that would encourage the use of customer-owned generation capability during times of high wholesale prices. The quickest and least expensive source of substantial DR capacity is to allow the use of this otherwise idle resource during critical peak times. We recommend that the SCC work with the Virginia Department of Mines, Minerals and Energy (DMME) and the Virginia Department of Environmental Quality (DEQ) to develop rules that will allow customers, CSPs and utilities to minimize the administrative process involved in deploying this resource, consistent with the protection of air quality.

- **Consider the qualification of certain clean DR options as renewable**

Some DR methods, not involving fossil fueled distributed generation, should be considered as counting toward renewable performance standards.

- **Continue the Workgroup to develop a Virginia Energy Action Plan**

Finally, we recommend continuation of the current Workgroup as a Virginia Energy Collaborative to develop and maintain a Virginia Energy Action Plan, continuing to identify and mitigate impediments.

- **Evaluate the adequacy of SCC resources to accomplish the recommendations of this report**

We believe additional resources will be required within the SCC to accomplish the recommendations of this report.

F. <u>Impacts of Peak Demand Management</u>

During periods of peak demand, the wholesale price of electricity purchased by Virginia in the regional PJM electricity market has at times reached the price cap of $1,000/MWh (August 2007) – more than 17 times the average price of $57/MWh. Virginia customer participation in demand response (DR) programs could reduce these peak wholesale power costs. Moreover, with aggressive action to reduce peak electricity demand over the next decade, Virginia utilities may be able to save millions of dollars by deferring some of the expensive additions to generation, transmission and distribution resources.

In addition to capacity benefits, peak demand reduction also can improve distribution system efficiency. It is often assumed that most distribution benefits stem from deferral of capacity expansion. In fact, an immediate benefit from peak load reduction is a significant reduction in line losses. This result occurs because on-peak distribution system losses can be in the 12 to 15% range, compared to about 5% on the average.

Recently published estimates of cost-effective demand reduction potential achievable over the next decade in Virginia range from 7.5 to 17% of the 2006 or 2007 summer peak demand. Unfortunately, neither of these published reports provided any quantitative information on the assumptions that led to their estimates.

The team had neither the data nor the resources to estimate an achievable and cost-effective amount of peak demand reduction. To create an estimate with a high level of confidence, it is essential to start with a baseline reflecting the factors that drive the current energy use patterns in Virginia. At a minimum, this analysis would consider the number and type of customers, saturation of electric end-use equipment and systems, and the expected evolution of these in the future. Customer and end-use load shapes and peak demand patterns would make the task much easier. However, notwithstanding current data limitations, the qualitative information assembled as part of this Subgroup's effort, recent national studies conducted by the DOE and others, and successful programs implemented by leading states provide a strong argument for proceeding with peak demand reduction efforts on an expeditious basis in Virginia.

- **Regional, State, and utility programs are all necessary to contribute to the achievement of the maximum practical demand reduction potential in Virginia.**

Although PJM has DR programs in place for reliability purposes, the PJM program does not provide appropriate incentives to defer expensive expansion of future generating and transmission capacity. However, PJM demand response programs play an important role in: (1) ensuring reliability during capacity shortages (emergency response programs); and (2) moderating prices by permitting demand response to compete with available generation resources (economic programs). The benefits of the PJM programs include reduced wholesale power costs, reduced peak demands and capacity needs, and increased reliability of supply.

Because PJM cannot assure the availability of cost-effective future supply for Virginia, State and/or utility programs are needed to focus on the reduction of future peak demand growth and the attendant Virginia capacity needs. The 2007 Virginia Energy Plan estimates that absent any substantial effort to control the growth of the peak, an additional 5,100 MW of supply may be needed over the next decade if the 2005 level of imports is to be maintained. Currently, Virginia has only modest programs and related rate designs in place on the retail side.

- **Demand response programs can result in substantial savings to consumers.**

A 3% reduction in peak demand has been shown to correspond to a 5-8% reduction of wholesale power costs during the 100 to 150 peak price hours.[4] During the past year, the prices for the Dominion Virginia Power zone of PJM during the 100 peak price hours ranged from $200 to $1,000 per MWh.

The DOE report cited above[2] estimates that the benefits of peak demand reduction would range from 50¢ to $2 per peak kW per year. These figures translate into gross savings for Virginia ranging from $16 million to $65 million in 2006 alone![5] This figure compares to an estimated 2006 total of more than $7 billion in Virginia customers' bills.[6]

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[4] Brattle Group, *Quantifying Demand Response Benefits in PJM*, January 2007. http://www.energetics.com/madri/pdfs/BrattleGroupReport.pd

[5] Based on 2007 peak demand estimated in the 2007 Virginia Energy Plan

[6] Based on Energy Information Administration, *State Energy Profiles: Virginia*, Sept. 2007. http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=VA

1. Background

A. Introduction

The importance of reducing peak electric demand has long been recognized by the Virginia General Assembly and the State Corporation Commission (SCC). However, State policymakers have failed to initiate comprehensive policies to address this challenge even though they recognized the important benefits to ratepayers more than 30 years ago. The time has come to address this problem.

Concern about peak demand was addressed as early as 1976 in a report required by the General Assembly and resulting legislation. More recently, this issue was addressed in a 1991 staff report to the SCC, in a 2006 SCC proceeding on time-of-use rates and advanced metering, and in legislation enacted by the General Assembly in 2007.

However, the picture of demand response in Virginia during the past three decades is one of missed opportunities. Yet, the need for action is more pressing now than ever, and it is essential for the SCC to take advantage of its new legislative authority to advance critical regulatory reforms. The multiple challenges of rapidly escalating fuel and electricity prices, global climate change, and energy security risks provide a clarion call for prompt action.

B. 1976 Report and Legislation

In a report to the Virginia General Assembly issued more than 30 years ago, the authors emphasized that "the reduction of peak demand [is] a major goal." The 1976 report further stressed that "[i]n the long run, the reduction of peak demand is the one area where savings to the ratepayer can be accomplished and it must be followed up."[7]

The 1976 report was prepared to respond to a legislative directive for the completion of a study on public utility regulatory reform. At that time, the Commonwealth of Virginia was faced with many problems which are apparent today. The price of fossil fuels was skyrocketing, and there were rapid increases in the cost of constructing new plants and infrastructure. In addition, energy security risks were a major concern.

It is noteworthy that the Senate report emphasized that the problems faced by Virginia in 1976 were not unique and that "every state legislature and every regulatory agency is confronted to some degree with the same questions concerning the actions that should be taken…." The report stated that "the controversies that are prevalent in Virginia abound in every state…."[8]

However, while several states initiated comprehensive policy reforms to encourage demand response as a result of the energy crises in the 1970s, the General Assembly and the SCC did not undertake similar action. In its 1976 legislative session, the Virginia

[7] REPORT OF THE JOINT SUBCOMM. STUDY OF PUBLIC UTILITIES, VA S. Doc. No. 21 at 17 (1976). http://leg2.state.va.us/dls/h&sdocs.nsf/Published%20by%20Year?OpenForm

[8] Id., at 6.

General Assembly did follow up on the Senate report with some important new legislation expanding the authority of the SCC in several areas, including conservation of energy and capital resources and the licensing of new facilities for power generation, transmission or distribution. The legislation directed the SCC to study the acts, practices, rates, and charges of public utilities to determine whether these firms are maximizing the "effective conservation and use of energy and capital resources" and authorized the SCC to order any changes necessary to promote these goals.[9] In addition, the licensing provisions were designed to enable the "Commission to anticipate and prevent rate increases based on unnecessary capital investments."[10] These provisions were spurred by the 1976 report, which underscored the serious shortages of capital and energy facing the country and the key role of public utility regulation in providing "minimum cost energy consistent with a long-term energy supply and environmental cost-benefits."[11]

However, this new legislative authority was construed to focus on individual licensing and rate cases rather than sweeping reforms. As a result, it is not surprising that a 1991 SCC staff report concluded that:

> The Commission has not adopted broad policy statements concerning conservation and load management, preferring instead to address such issues on a case by case basis. The Commission's 'policy' regarding conservation and load management, therefore is not a comprehensive policy statement, but rather a collection of orders and administrative practices established in various cases and proceedings over the last twenty years.[12]

C. <u>1991 SCC Staff Report</u>

In April 1991, the SCC issued a staff report to review "what Commission policy was necessary to promote optimal investment in demand-side resources on the part of utilities in Virginia."[13] The staff identified numerous impediments to energy efficiency and demand response and recommended specific steps that should be undertaken by the SCC to overcome these barriers. The staff report urged that the policy reforms should "fully promot[e] cost effective conservation and load management programs on the part of electric and gas utilities operating in Virginia."[14]

The recommendations set forth by the SCC staff in 1991 were extensive and included the following:

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[9] VA Acts of Assembly 1976, ch. 379, *codified at* VA CODE Ann. Sec. 56-235.1. *See also*, *Twenty-First Annual Survey of Developments in Virginia Law, 1975-1976,* 62 VA. L. REV. 1352, 1360-62 (1976).
[10] *Twenty-First Annual Survey of Developments in Virginia Law, 1975-1976,* 62 VA. L. REV. 1352, 1361 (1976).
[11] REPORT OF THE JOINT SUBCOMM. STUDY OF PUBLIC UTILITIES, VA S. Doc. No. 21 at 5 (1976).
[12] Virginia State Corporation Commission Staff Report, *Review of Commission Policy Toward Conservation and Load Management Programs,* Case No. PUE-900070, at 11, April 26, 1991.
[13] <u>Id</u>. at 1.
[14] <u>Id</u>. at 18.

- Removing any disincentives associated with conservation and load management and providing necessary cost recovery practices that place demand-side options at least on a par with supply side options;
- Subjecting utility demand-side programs to formal approval by the Commission;
- Modifying the Commission's policies to allow various promotional allowances to customers, including incentives to encourage customers to purchase high-efficiency appliances or equipment;
- Reviewing the impact of rates on conservation and load management in future rate cases; and
- Developing an experimental demand-side bidding program.[15]

D. 2006 SCC Proceeding on Time-of-Use Rates and Smart Metering

In February 2006, the SCC established a proceeding to consider for implementation in the Commonwealth the new federal standard enacted in section 1252(a)(14) of the Energy Policy Act of 2005. This provision required each state public utility commission to investigate and issue a decision on the appropriateness of issuing a standard offering all electric customers time-of-use rates and advanced metering and communications technology. The SCC received comments from a variety of interested parties, including several members of the Energy Efficiency Working Group, urging the adoption of the federal standard because of the benefits of time-of-use rates.

On the other hand, the investor-owned utilities opposed the adoption of the order for several reasons. First, they asserted that their tariff offerings already offered time-of-use metering and rates. Second, these utilities noted that those who purchase electricity from third parties are entitled to the same time-based metering and communications as third parties. Third, several of the utilities asserted that there is no real demand for time-based metering options and that participation in such options has been limited. Fourth, they expressed objection based on existing rate caps.

The SCC staff recommended against the immediate adoption of the Federal standard but also urged that the Federal standard should not be completely dismissed pending the outcome of electric restructuring in Virginia. The staff stressed that a program of time-of-use rates and advanced metering and communications "may provide customers with protection against more volatile rates and possible increases to consumer bills."

In July 2006, the SCC issued its final order in the TOU proceeding.[16] The Commission expressed general agreement with the staff recommendation. They rejected the immediate adoption of the Federal standard but left the door open to future action.

However, the rationale of the SCC is worth noting in conjunction with the findings of this Subgroup report. The Commission asserted as part of their rationale that:

> [t]here appears to be minimal customer demand for such [time-based] rate schedules, even for those that currently exist. Customers may not be capable of or willing to, among other things, vary demand and usage in response to

[15] Id., at 56-57.
[16] Final Order in Case No. PUE-2006-00003.

> changes in prices based on specific time periods, manage costs by shifting usage to lower cost or off-peak time periods, or reducing consumption…."

E. 2007 Legislation – A Window of Opportunity

Although numerous states initiated aggressive and effective demand response programs in the 1970s, 1980s, and 1990s,[17] Virginia continues to lag far behind. However, legislation enacted in the 2007 session of the Virginia General Assembly provides another window of opportunity for action in the Commonwealth of Virginia.

In April 2007, the General Assembly of Virginia enacted legislation that, among other provisions, established:

> That it is in the public interest, and is consistent with the energy policy goals in section 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 consumers in 2006.[18] (emphasis added)

The 2007 legislation should be read in conjunction with the provisions of the 1976 legislation, requiring conservation of capital and energy resources, since these provisions remain in effect.

Although the 2007 legislation did not include a specific percentage reduction goal for demand response, the legislation clearly supported the promotion of demand-side management and load management. Moreover, the Commission's 1976 directive to achieve the strong ratepayer benefits of reducing peak loads remains as critical provision of the Virginia Code.

Moreover, new opportunities are now available to harness the potential for reductions in peak demand, and these new opportunities provide a further impetus for accelerated action. These new opportunities are the result of: (1) development of new policies in the PJM market requiring the treatment of demand response on a par with supply-side options; (2) advances in telecommunications that allow for real-time communication

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[17] Some states acted after the energy crisis in the mid-1970s. Others acted in the 1980s to require integrated resource planning -- with energy efficiency and demand response considered on a level playing field with new supply in determining future electricity resources. A third set of states, including Connecticut and New York, acted in the late 1990s to require the initiation of energy efficiency and demand response programs as a prerequisite to the enactment of electricity restructuring legislation. Other states (e.g, Vermont, Minnesota, Wisconsin) developed legislation to address the need for stable funding for efficiency and demand response programs without restructuring their state electricity markets. U.S. Environmental Protection Agency and U.S. Department of Energy, *National Action Plan for Energy Efficiency,* at 6-11, 2006.

[18] VA Act of Assembly 2007, ch. 933.

among wholesale electric suppliers, retail suppliers, and customers; and (3) improvements in the affordability and functionality of demand response technology.

F. Conclusion

It is essential for the SCC to take advantage of new legislative authority granted in 2007 (as well as preexisting legislation enacted in 1976 requiring conservation of capital and energy resources) to meet these pressing needs and harness the new opportunities. The time is now to implement critical regulatory reforms that will spur reductions in peak demand. The 2007 legislation provides another window of opportunity for action in the Commonwealth of Virginia to promote demand-side management. Virginia ratepayers and the State's economy and environment will suffer if this opportunity is squandered.

2. Demand Response (DR): What, Why, and How

A. What is Demand Response

Demand response (DR) is part of the arsenal available to reduce customers' electricity costs. It complements energy efficiency measures by offering a tool to reduce electricity use for a limited period (typically two to four hours, 10 to 15 times per year) at the "push-of-a-button." Somewhat similar to energy conservation, demand response generally implies a "do without" approach. This compares to energy efficiency measures, which create a lasting, "round-the-clock" reduction in use by reducing the amount of electricity required to provide a service, but may or may not result in a significant reduction of electricity use during peak hours.

One category of demand management measures shifts the load away from the peak hours. These measures reduce the peak demand (kW) by deferring electricity use required for a service or process to other times of the day, but may or may not reduce electricity use (kWh). Examples include deferral of an industrial process, water pumping, irrigation, or dish- and clothes-washing for residential customers. Energy storage, generally for heating, cooling, or water heating, can be employed to provide the service when desired, but move the corresponding electricity consumption away from peak hours. Because cooling represents one of the largest contributions to the summer peaks, this is a particularly effective approach for decoupling the time of the delivery of the service from the time when the electricity for this service is consumed. However, this is also more expensive than other peak demand reduction techniques.

As described above, there are many different approaches to DR; hence, some confusion arises due to varying definitions. For purposes of this document and to focus on those initiatives applicable to this Subgroup's scope, demand response is defined as the change in a customer's behavior and its electric load profile in response to a change in price, a direct-load control action/signal initiated by the utility (or under utility control), information, or receipt of a payment or incentive. Demand response may take the form of a decrease, or an increase, in the customer's electricity use. For example, a Critical Peak Pricing tariff may influence a customer to reduce loads during the critical peak periods, by shifting (and thus, increasing) loads to a non-critical peak period.

Retail customers may participate in demand response through initiatives at the retail level (e.g., utility-sponsored) and/or at the wholesale level (e.g., ISO/RTO-sponsored), and in a variety of ways. Such participation may include utility-sponsored demand response programs (e.g., air conditioner load control) or a utility's tariff-based demand side management initiative, such as Critical Peak Pricing. Retail customers' participation in wholesale demand response programs, such as those offered by PJM (e.g., Economic or Capacity Load Response Programs), would be as part of an aggregation of customers by a utility or a Curtailment Service Provider (CSP).

There are two basic types of demand response programs: dispatchable and non-dispatchable. Dispatchable programs provide a capability to trigger the program in real-time or at some time specified ahead. They may or may not include a dynamic pricing element. Non-dispatchable programs, such as time-of-use (TOU) rates, are designed to lower predictable peaks.

B. <u>Why Consider Demand Response</u>

Electricity is a unique commodity in that it is absolutely essential to our health, safety, life style and business operations; yet it is currently difficult to store economically in anticipation of infrequent surges of demand for it, primarily weather related. These surges have traditionally been accommodated by the construction of substantial reserve generation and transmission capacity that is only required for approximately a hundred hours a year. The cost of this capacity has been averaged into the standard electricity rates. Part of the over 5,000 MW of new capacity needed over the next ten years is for maintaining this reserve. DR is generally focused on impacting (reducing) peak demands of the utility, not necessarily the individual end-use customer's peak demands. As a result, DR assists in deferring or eliminating the need for a supply side resource (e.g., generation capacity) for reserve purposes, and assists in alleviating congestion in the transmission system.

DR can be viewed as a risk management tool, providing utilities and end-use customers with viable alternatives to generation supply, transmission and/or distribution reliability concerns or issues. In addition, the application of DR will tend to dampen or reduce the applicable market clearing price (or lower the marginal generation cost/system lambda) through the process of economic dispatch, lowering costs for all customers, including non-participants.

A secondary benefit of DR is to reduce energy costs, either fuel or purchased power costs, typically targeting the (relatively) few hours adjacent to or containing the critical peak demand periods.

Other benefits of DR may include improved air quality and the environmental benefit of deferring the need for generation, transmission and distribution infrastructure.

The issues associated with deferring different types of capacity are different.

There is ample experience from the 1980's in deferring generation, primarily through residential and large commercial/industrial programs. While the technology and program designs needed to accomplish the impact have evolved, the detailed information available for load response characteristics has remained pertinent and been confirmed in more recent studies.

On the other hand, experience with deferral of transmission and distribution (T&D) capacity is not as mature. A number of analyses of the potential and suggestions of program design have been carried out in the 1990's.[19] The controlled loads and measures have to be location-specific, and power flow simulations are required to ensure that the programs have the intended impact.

C. Pricing and Rate Design for Demand Response

It is very rare that electricity cost savings alone will compensate a customer for the cost of participating in a demand response program, if valued by the kWh reduced at the standard billing rate at the time of the reduction. Further, electricity represents a small fraction of most industrial products (see list below); only very few electricity-intensive industries are still operating in the United States. Because of that, it is not always cash that is required; for example, some industrial customers participate in return for being in the last outage block. On the other hand, for customers with very low profit margins, such as supermarkets, energy costs may represent just about the only option to reduce operating costs. Still other customers may become participants by providing an added functionality to their control systems already designed to reduce the demand component of the bill.

Electricity dollar content of product value:

- Electrolysis (electrical separation of materials, such as in production of hydrogen and chlorine) and air separation for the production of industrial gasses, such as nitrogen and oxygen (10% to 50%)
- General manufacturing (5% to 10%)
- White collar (1% to 5%)
- Computers and information (less than 1%)

A number of pricing approaches exist that can be used to encourage reduction in electrical load during predictable or unpredictable times of peak demand. Such approaches are generally designed to either approximately or very precisely reflect variations in the cost of producing or purchasing electricity over time and to send signals to the customer reflecting that price. Dynamic pricing methodologies or rebates and incentive payments are effective tools in encouraging customers to voluntarily reduce load during times of peak demand or to shift load to off-peak periods. Programs are emerging that create a closer degree of correlation between the dramatically higher prices for electricity during critical peak times in the wholesale market and the compensation mechanism employed to reward customers that can reduce demand at that precise time. Rates can be designed such that long- or short-term variations in pricing can be accommodated. Each of these approaches or a combination thereof can be used to support a demand response program.

[19] See, for example, Yau, T.S., et al, Demand-Side Management Impact on the Transmission and Distribution System, IEEE Transactions on Power Systems, Vol. 5, Issue 2, May 1990. http://ieeexplore.ieee.org/xpl/freeabs_all.jsp?arnumber=54560

◆ **Pros & Cons: Pricing vs. Incentives (bill credits)**

- Utility pricing is typically based on annual average demand and energy cost where the utility assumes the risk and retains a greater portion of revenue generated from the market. PJM programs allow the end user to retain more of the revenue by assuming greater risk.
- Incentives to encourage energy efficiency improvements should be reimbursed based on avoided cost of generation and offered in addition to any pricing options.

◆ **Time of Use Rates (TOU)**

- Energy prices that are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year (summer and winter season). Prices paid for energy consumed during these periods are pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and to manage their energy costs by shifting usage to a lower cost period, or reducing consumption overall. The time periods are pre-established, typically include from two to no more than four periods every day except weekends and holidays, and do not vary in start or stop times.
- Cost savings for shifting load to off-peak periods when base load generators are not fully loaded. Improves the utility's load factor and typically reduces the cost of kWhs and should continue to be part of conservation initiatives.
- Demand charges should be used to reward on-peak energy conservation efforts and penalize poor performance.

◆ **Dynamic Pricing (dispatchable rates)**

Retail prices for energy consumed that offer different prices during different time periods and reflect the fact that power generation costs and wholesale power purchase costs vary during different time periods. Types include dynamic versions of Time-of-Use Pricing, Critical Peak Pricing and Real-Time Pricing.

- Real Time Pricing (RTP): Where energy prices are set for a specific time period on an advance or forward basis and may change according to price changes in the wholesale generation spot market. This may be very costly to administer but offers significant savings when load shifting.
- Critical Peak Pricing (CPP): A type of dynamic pricing whereby the majority of kWh usage is priced on a TOU basis, but where certain hours on certain days (typically 12-15 days per summer) when signaled by the utility or ISO are subject to higher hourly energy prices.
- Peak Time Rebate (PTR rate): For a fixed number of peak hours during the critical peak days when signaled by the a utility or the ISO (typically 12-15 days per summer) customers receive a rebate equal to the critical peak price minus the current flat rate during critical peak hours.

D. DR Implementation: The Role of Utilities and Third-Party Providers

Virginia Senate Bill 1416/House Bill 3068 acknowledged that an entity other than utilities may be better positioned to administer some aspects of the Commonwealth's demand side management and conservation efforts. The legislation states that the programming activities by "electric utilities, public or private organizations, or both" may be used to promote the Commonwealth's energy policy goals.

Due to their substantial expertise in the technical aspects of load management, specific knowledge of their electrical grid systems, relationships with their customers and existing administrative mechanisms, utilities are best positioned to develop, implement, and administer demand side management programs that involve direct load control, active load management, advanced metering, communication protocols, distributed generation, time-of-use and critical peak pricing. A new industry of companies called Curtailment Service Providers (CSPs) is emerging and growing rapidly in the United States. These companies generally assist utilities in deploying outsourced DR and energy efficiency programs. For example, the DMME recently awarded such a contract for the Commonwealth's own facilities. In some jurisdictions, these CSPs also directly aggregate retail customers to respond to PJM's wholesale DR programs. Utilities also often function as aggregators of their retail customers. They frequently use third parties to develop and maintain the programs,
but they tend to retain the dispatch function.

Energy efficiency and conservation programs that involve initiatives such as consumer education, rebates and incentives to encourage the adoption of higher efficiency equipment and market support functions are best administered through a non-utility third party such as a state agency or private sector organization. Providing such information and programs on a consistent basis throughout the Commonwealth will ensure that all customers will receive an equal opportunity to take advantage of all programs, regardless of whether the customer is served by an investor-owned utility or cooperative. Examples of states in which non-utility entities have been assigned responsibility to administer such programs are Vermont, New York and North Carolina.

E. DR Technology

Short-term reductions in electrical load during times of peak demand are generally facilitated by sending a signal of some type to the end user of the electricity. The signal can take the form of a pricing signal, an electronic control signal or an informational signal.

A broad range of demand response technologies is available for transmission of the pricing signal and to enable an appropriate response to that signal. The range of technologies continues to evolve with new and enhanced versions appearing on the market or in development. With appropriate incentives and pricing, the expertise and creativity in the market place will continue to develop new technologies aimed at reducing electrical loads and electricity bills at times of peak demand.

Included among the technical options are switches for control of specific devices, remotely controllable thermostats, energy management systems with automatic demand control, computer-controlled load management systems, improved communications technologies (both customer premise and wide-area networks), improved advanced metering technologies with built-in demand-response functionality, Internet-controlled systems and integration of other subsystems with on-site generation and/or renewable energy sources.

When developing a demand response program, it should be flexible enough to accommodate a number of approaches and technologies appropriate for a variety of customers as well as the operational requirements of the utilities. An effective program should take advantage of developing technologies and should be as broadly compatible across devices and systems as possible to maximize useful life of equipment and to maintain options for expanding the scale of existing programs.

The various types of systems generally respond to either a real-time signal transmitted by a local utility via some communications protocol or pre-programmed information. In the case of the real-time signal transmitted by or on behalf of the local utility, the information transmitted can consist of a simple on/off signal used to trigger a remotely controlled switch which temporarily curtails operation of a specific device or circuit. Such devices can include heating and air conditioning equipment, water heaters, pool pumps, lighting circuits or other high-load electrical devices. The transmitted information can also contain more instructions that can be used to ramp operation of a device up or down or send temperature adjustment information to a thermostat. Price information can also be transmitted to allow a customer or automated device to choose to either respond to the signal or not.

Communication technologies that can be used to send control signals or pricing information include radio frequency, power line carrier systems, cell-phone networks, wide area wireless networks, broadband over power line and Internet, to name a few. The simplest systems involve the use of one-way radio-paging signals. More complex systems can make use of two-way communication capabilities between metering systems and utility central computer control systems. One emerging technology uses computer control to integrate delivery of power from a renewable energy source with backup battery supply and curtailment of load when needed or when favorable to do so based on real-time power pricing.

◆ Equipment and System Architecture

A typical architecture of a DR system that accommodates the various system elements described above is shown in Figure 1 below.[20]

This figure illustrates the complexity (and simplicity) of technology required to implement a DR program, but perhaps more importantly, it shows the various elements that need to be considered in designing and costing the program.

[20] Adapted from Rabl, V., "Evaluating and Measuring Demand Resources," Proceedings of CBI's 3rd Annual Demand Response Programs Conference," Alexandria, VA, March 2004. The acronym M&V on the right hand side of the figure stands for "measurement and verification."

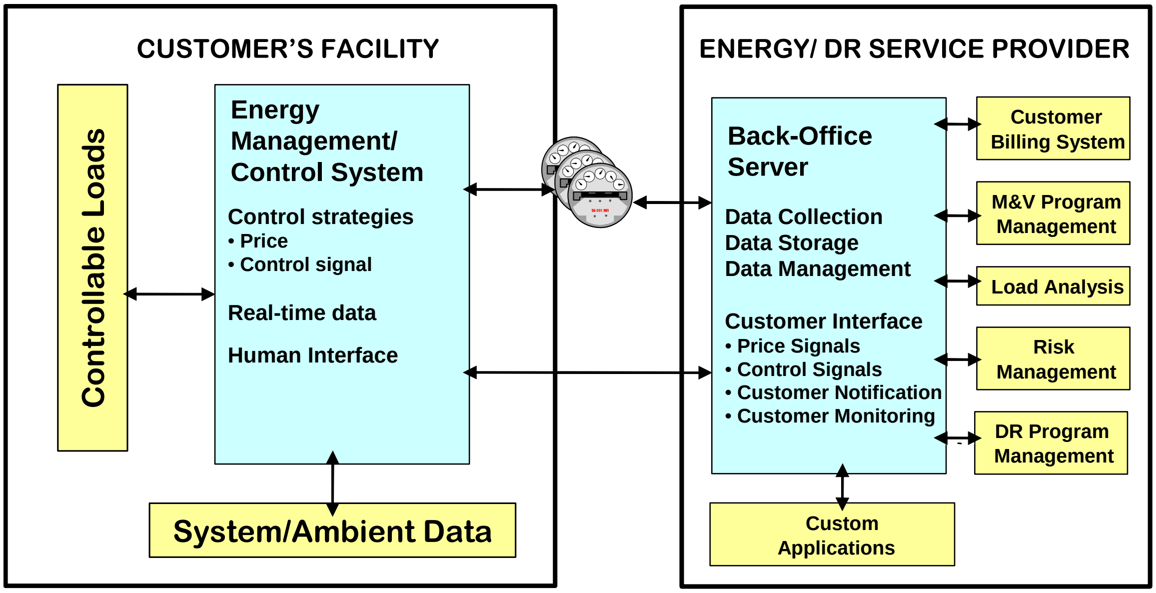

Figure 1. Elements of system architecture

It is often assumed that small business establishments (the "under-served" customer class) are poor targets for demand management. In fact, many of them are willing to pay for a demand management system just to control their demand charges and bill. Their system can then be interfaced with a DR program and dispatched if needed. A report prepared for Southern California Edison provides numerous examples of equipment and systems appropriate for small business customers.[21]

◆ Elements of DR cost

There are a number of elements that should be considered in determining the implementation costs of DR programs. There are often many different alternatives that result in the same or similar outcome, so a proper costing approach is essential and can be used to consider trade-offs between costs and functionality.

Typical cost elements include:

- Equipment and installation costs. This is often the simplest cost element to establish either through RFPs or experience in other programs. Includes control equipment installed on customer premises, metering (if required by the rate schedule), as well as communications and dispatch infrastructure.

- Operation and maintenance costs. In addition to the equipment maintenance, this category also includes the maintenance of the DR capacity. Customers can

[21] Lockheed Martin Aspen, Demand Response Enabling Technologies for Small-Medium Businesses, prepared for M. Martinez, Southern California Edison, April 2006. http://www.energy.ca.gov/demandresponse/documents/group3_april18_workshop/LMA_DR_ENABLING_TECHNOLOGIES_SMB.PDF

drop out, move, change their systems, and new customers may need to be recruited to compensate for the decline in the demand resource.

- Measurement and Verification. Includes costs of metering, data acquisition, and data analysis.

- Data Processing. The large amounts of data collected in these programs would probably require new back office computer hardware and software, as well as interfaces of the software to other business and/or customer service systems.

- Marketing costs. This cost element is often not fully included or even ignored. However, even at relatively low market penetrations, it can easily overwhelm equipment and installation costs. After screening for suitability for the program (often requiring a site visit), cost-effectiveness, and willingness to participate, the final program participants may well represent only a small fraction of the initial target market. This category also includes the cost of marketing staff, educational and marketing materials, as well as advertising costs. The almost total lack of awareness of customers about DR and how to benefit from it is a huge factor. Some of these options have not previously existed for most classes of customers. The general perception is that there are only two ways to save money on electricity – use less or accept significant inconvenience. New technologies combined with new options from utilities can change that but an entire population needs to become educated that a paradigm shift has occurred.

- Intangible costs. While difficult to quantify, transaction costs may be very important to the customer. It is often impossible to recruit a customer, even if there are obvious financial benefits associated with program participation. For example, the cost/kW to recruit commercial and industrial customers may be lower than that for the mass market, yet most of US programs focus on the residential sector, because the customers are much easier to acquire. On the positive side, the utility or service provider could take advantage of the new data acquisition capabilities to create new product offerings. For example, the hourly load profile information allows analysis of operational practices by the customer, such as realizing that a company is turning on all A/C equipment at the same time of the morning, when prices are higher than a few hours earlier. Significant energy efficiency and demand control opportunities can often be discovered simply because of the increase in data availability.

A recent paper presented at the AESP conference includes a good discussion of these typical cost elements.[22]

[22] McCarthy, P., et al., A Demand Response Solution for Underserved Mid-Size Commercial Customers, Proceedings of the17th National Energy Services Conference, Las Vegas, NV, 2007.

F. Advanced Metering Technology and Advanced Metering Infrastructure (AMI)

◆ Introduction

Another emerging technology for enabling demand management is based on the use of advanced meters and the concept of an Advanced Metering Infrastructure (AMI). AMI is not a specific technology; rather, it is an infrastructure that has at its core a bi-directional network with advanced meters. FERC[23] defines AMI as:

> "The communication hardware & software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers, retail providers and the utility."

The actual meter capabilities depend on the selection of specific meters and communication capabilities from technology suppliers. In general, the primary benefit of creating an AMI is the ability to quickly process large amounts of pricing and usage data and make such data available to both the customers and the service providers. AMI not only offers opportunities for sophisticated load management measures behind the meter, but it also provides a platform for potential benefits for utility operations in areas such as remote service connects/disconnects, outage management, theft detection and remote load control.

AMI is not a prerequisite for demand response; rather, it should be viewed as a significant option to enhance opportunities for communicating prices to customers in real- or near-real time, accelerating measurement and verification of demand changes, and facilitating faster data processing and settlement. One day, AMI may become part of a "Smart Grid"[24] -- a network tying together and coordinating supply-side resources with customer processes.

Meanwhile, initial demand response programs should be made available to customers using existing metering capabilities (such as interval meters). The design for the next generation of demand response programs should include a thorough evaluation of AMI capabilities relative to other alternatives and should take advantage of the range of technologies available to the extent that they can be integrated into an overall coordinated program and are designed to be cost-effective. Interoperability among devices should be one of the focal points of such an evaluation; as this is important to ensure that the utility retains the flexibility to use multiple technology vendors.

◆ Advanced Metering Functionality

Advanced meters can provide up-to-the-minute information on energy pricing and customer usage. In addition, they may incorporate a number of added functions.

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[23] FERC, Assessment of Demand Response and Advanced Metering, Staff Report, Aug. 2006. http://www.ferc.gov/legal/staff-reports/demand-response.pdf

[24] Referenced in the pending Energy Bill

For example, current technology leaders offer the following advanced meter functionality via Two Way Command and Control:

- Time of Use (TOU)
- Remote connect and disconnect services
- Interval data (hourly and subhourly)
- Coincident and off cycle demand reads
- Move-in, move-out readings
- Multi-utility (e.g., water and gas) solutions
- Remote administration
- Outage/restoration management
- Plug-and-Play meter deployment
- Tamper and theft detection
- Reverse energy monitoring
- Load research
- Voltage reads
- Daylight savings
- Network management
- Asset tracking

◆ **Interoperability and Open Architecture**

- Interoperability means that one technology company’s technology/service has the ability to interface with other technologies or services.
- A key element in any advanced metering infrastructure (AMI) is the ability to leverage the infrastructure investment to the fullest extent possible.
- The distinction between “open” architecture and proprietary technology/services is very important.
- The meter technology company’s network infrastructure, from back office software to the meters (and into the home), should be designed to leverage existing communications standards and open protocols.
- On the electricity side, all meter manufacturers, while employing ANSI standards, utilize manufacturer tables which result in a proprietary way to obtain meter data.
- While one may employ standards, there is not a single end-to-end solution in the industry that is not proprietary in some manner.

G. Distributed Generation for DR

Many commercial and industrial facilities with stringent power reliability requirements use backup generators to supply replacement power. Typically, operation of these units is limited to a few hundred hours per year, during power outages, precautionary times when severe storms are approaching, and periodic testing.

While unlikely to completely eliminate the need for new generation or transmission facilities, use of backup generators on a very limited basis as part of a distributed generation fleet can potentially defer construction of new electrical infrastructure by reducing overall load on existing generation and transmission equipment. During times of peak demand, on-site generators can be used to produce electricity locally at commercial or industrial facilities, enabling those facilities to remove all or part of their load from the electrical system. Combined with other load curtailment measures, distributed generation can serve as a bridge to accommodate growing demand while electrical infrastructure assets are in the development stage.

For the most part, backup generation systems consist of reciprocating engines or in some cases combustion turbines, with a small portion of backup power now supplied by micro-turbines. Solar photovoltaic systems, coupled with battery systems, are being used to supply a small but growing segment of the backup power needs.

Since most combustion-based backup generator systems are used infrequently and since the total amount of generating capacity from these types of systems is limited, impact to air emissions is similarly limited. While dispatch of backup power systems, when used in a demand response mode, may require increased run time to supply power during times of peak demand, such increases are generally modest since periods of peak demand are typically very infrequent - totaling only a few percent of the hours in a given year, leaving the equipment idle for the vast majority of time. The environmental impact anticipated from such increases in run time, if required, would similarly be expected to be minimal with the possibility of reducing the amount of time required for generator testing. Although anticipated to be minimal, impacts from combustion-based distributed generation are required to be addressed under environmental regulations on a case-specific basis. Environmental controls must comply with state and federal standards. New or modified installations typically must install controls for air emissions of nitrogen oxide and use low- or ultra-low sulfur fuel. In many parts of the nation where the distributed generation resource is being used for DR, utilities, CSPs and customers, or some mix of them, are upgrading the environmental controls on the customer’s equipment to further reduce the adverse environmental impact of this option.

Although there is no single approach to demand response that will completely fill the need for active load management measures, using the fleet of backup generation equipment as part of a distributed generation system can be an extremely effective component of a comprehensive demand response program and can provide a means to significantly reduce load on utility electrical systems.

H. <u>DR Programs and Expenditures in the US</u>

According to the FERC report[23] the total potential demand response resource contribution from existing U.S. programs in 2006 is estimated to be about 37,500 MW. The vast majority of this resource potential is associated with incentive-based demand response, i.e., interruptible/curtailable programs and dispatchable remote appliance control programs.

Some of the history of demand response is described in an ACEEE report and reproduced below:

> "The DSM era of the 1980s and 1990s saw extensive investments in DSM programs-both load management and energy efficiency programs. Such spending peaked in 1993 at about $2.7 billion nationwide. Since that peak, utility DSM spending has declined significantly, largely due to industry restructuring-in 2003, this value had fallen by about half, to $1.3 billion (EIA 2004). Of this total, about $800 million was for direct costs of energy efficiency programs, about $350 million was for direct costs of load management programs, and the balance of about $140 million was for indirect costs associated with both kinds of programs. Impacts from these programs are significant. In 2003, the total actual peak-load reduction achieved from utility DSM programs was 22,904 MW; of this total, 13,581 MW is attributed to impacts from energy efficiency programs and 9,323 MW is attributed to impacts from load management programs." [25]

Many of the new utility-conducted DR programs focus on dynamic pricing for residential customers. The following are examples of programs approved or pending approval for full scale implementation:[26]

- San Diego Gas and Electric: Peak time rebate (PTR) program (pending approval of CPUC)
- Southern California Edison: Peak time rebate (PTR) program.
- Pacific Gas and Electric Company: Critical peak pricing (CPP) program

In addition, the following dynamic pricing pilots are currently underway or have been recently completed in North America:

- Ameren, Missouri (CPP, TOU) – preliminary results
- Anaheim, California (PTR) – preliminary results
- BGE (CPP, possibly PTR) – pilot will occur in 2008
- Commonwealth Edison (RTP) – results available
- Hawaiian Electric, Hawaii (CPP, PTR) – planned for 2008
- Hydro Ottawa (CPP, PTR) – preliminary results recently released
- Idaho Power, Idaho – preliminary results
- Pepco, DC (CPP, PTR, RTP) – will begin late summer 2007
- PSEG, New Jersey –will begin in 2008
- SMUD, California –concluded, no results publicly available

[25] ACEEE. Exploring the Relationship between Demand Response and Energy Efficiency, report U052, March 2005, p.10
[26] Private communication, The Brattle Group

3. Virginia Situation

A. Current and Projected Electricity Usage, Demand and Costs in Virginia

Total annual electricity consumption in Virginia is approximately 110,000 million kWhs. This consumption is divided among residential users (40%), industrial users (20%) and commercial users (40%).

Annual electricity use per person in Virginia is approximately 14,400 kWhs/yr, which is higher that the US average usage of approximately 12,350 kWh.

Virginia's per capita use of electricity is also higher than that of several nearby states.

Annual Electricity Usage[27]

PA	11950	kWh/person
MD	12230	"
VA	14400	"
DE	14420	"
NC	14800	"
WV	16620	"

72% of residential energy usage (electricity, gas and other) in Virginia is for three uses: heating and cooling (49%), water heating (13%) and lighting (10%). Cooking, food storage, electronics and various other appliances account for the rest.

Use in commercial establishments is primarily for cooling, heating, and lighting, though a rising use is for information processing. Data centers, which are an important growth area in Virginia's economy, use significant amounts of electricity per square foot of space for both the equipment itself and for cooling.

Industrial users also use electricity for cooling, heating and lighting, but their primary use is for motor drives.

However, use of electricity is not level, but varies during the year with usage highest on cold winter days from electric heat and even higher on hot summer days as a result of high air conditioning usage. This is significant because the level of highest demand for electricity determines the total amount of generation required by the electric system and determines the amount of transmission and distribution capacity the system must have for reliable operation and also requires the use of expensive fuels used only during times of high system electric demand. The summer peak in Virginia is especially significant because electric transmission and distribution systems are reduced in carrying capacity during hot weather. Thus, even more capacity must be added to meet high summer peak demand.

The Virginia electric system peak demand occurs normally in July or August. It totaled approximately 33,000 MW in the summer of 2007 according to the Virginia State Energy

[27] "US Per-Capita Electricity Use by State" California Energy Commission, 2005. www.energy.ca.gov/electricity/us_per_capita_electricity_2005.html

Plan. This peak is almost 2½ times higher than the average demand in the state of 13,000 MW and is predicted to grow at a rate of 1.9% per year for the next decade. These peak demands, which last for only about 100 hours per year, determine the required capacity of the utility infrastructure in Virginia

As the figures below indicate, the current retail price of electricity in Virginia is low compared to the US average, which has been an important factor in reducing interest in electricity conservation and demand reduction.

US and Virginia Electricity Prices (Source EIA)[28]

Residential:	VA 8.30 cents/kWh	US 10.27 cents/kWh
Commercial:	VA 6.17 cents/kWh	US 9.32 cents/kWh
Industrial:	VA 4.88 cents/kWh	US 6.18 cents/kWh

These prices will increase in the future, potentially driven by significant planned additions to generation and transmission capacity, including two nuclear units, additional coal-fired plants and major high-voltage transmission lines. Further, a recent study by the Brattle Group for the Edison Foundation has pointed out that new power generation construction costs are rising much faster than inflation, which will put additional pressure on electricity costs. Additionally, new environmental restrictions, potential carbon taxes and continued increases in the cost of fuels, especially natural gas will drive up Virginia's power costs.

With the elimination of the price cap, and the renegotiation of fuel prices, these fundamental pressures on costs will cause rates for retail electricity to rise soon and throughout the next decade and beyond.

Costs of producing electricity are particularly high during peak times because the system is forced to dispatch its least efficient plants and use its most expensive fuels during that time. A good measure of the instantaneous cost of producing electricity is PJM's "Locational Marginal Price", or LMP,[29] the price at which it will buy or sell wholesale electricity during any one hour in one of its zones.

For example, in the most recent year, PJM's average LMP over the past year for Dominion Virginia Power (PJM's DOM zone) was $57.00/MWh or 5.7 cents/kWh. In August 2007, the average LMP in DOM was $94.00/MWh. During the highest 28 hours in the DOM zone in August 2007, the LMP exceeded $500/MWh and during the single highest hour in August, 2007 the price was $1000/MWh or $1.00/kWh[30]. And this is just the price of wholesale electricity, not the retail price to most end use customers, which would be higher still.

However, under Virginia's current rate structures, for most customers these peak costs are averaged into standard rates so almost all customers do not see these high peak time costs and, thus, have little incentive to reduce demand at those times.

[28] "Average Retail Price of Electricity to Ultimate Customers by End Use Sector by State", Energy Information Administration, DOE, Sept. 2007.
[29] LMP is a pricing mechanism to approximate optimal power flow in the system as currently configured.
[30] See PJM website, http://www.pjm.com/markets/jsp/lmp.jsp

These peak demand electricity costs can be expected to continue to rise as peaking plants (run only during periods of very high demand) and transmission capacity are added to maintain the ability to serve customers during these periods of particularly high and rising electricity demand levels. Further, since natural gas is the fuel used to satisfy peak demand levels, expected increases in gas prices will add even more to increases in peak electricity costs.

Demand Response programs can reduce demand for electricity during these periods of high usage and high costs through either voluntary reductions in usage during these periods or through control systems that can turn off or turn down certain equipment and appliances during these peak periods. These programs are usually supported by prices that expose users to both the very high costs of electricity in peak times and the lower costs at other times and by direct payments to customers for their willingness to have their usage reduced during peak times.

The particularly high costs which can be avoided, and the relatively brief times during which reductions are required, make many programs of control and peak reduction cost-effective.

B. Existing Demand Reduction Programs in Virginia

A variety of programs currently exist in Virginia to aid in reducing demand during peak usage times, but participation levels are low in most cases.

These existing programs include:

- CPP rates, available to some of Virginia's largest commercial and industrial customers;
- Some participation by larger electricity users in PJM's various demand response programs;
- Some existing time-of-use (TOU) rates; and
- Several programs for control of residential air conditioning and hot water heaters.

In addition, Virginia has also installed some advanced metering systems that include both interval meters and communication systems to allow monitoring and control of short-term usage.

C. Overall Assessment of Virginia Demand Reduction Situation

Relatively low rates for electricity and poorly designed TOU rates in Virginia have reduced interest in electricity conservation and demand reduction programs. Current participation in demand reduction programs is small, and the programs which exist are not particularly targeted to the highest periods of power demand and cost.

However, as Virginia moves toward a rising electricity cost and price environment, it has significant opportunity to implement effective demand reduction programs. Further, it can move efficiently and swiftly, using the substantial experience gained elsewhere.

Programs in Virginia to reduce demand during peak times are modest, as the following illustrations indicate:

(1) TOU rates are designed to expose customers to high peak time costs and to lower off-peak costs as well, providing an incentive to reduce peak time usage. However, although peak time costs are actually highest during only about 100 hours per year, current rates in Virginia spread those costs over thousands of hours for most customers, significantly diluting their effects.

(2) Meters capable of measuring electricity use during short intervals of time and communicating that usage to a control center facilitate the more sophisticated demand reduction programs since they provide the basis for assessing individual usage patterns and triggering various control systems. However, in Virginia only about 4.2% of customers have such meters installed.

In comparison, according to a 2006 study by the Federal Energy Regulatory Commission (FERC)[31], U.S. leaders in advanced meter installation included:

- PA 52.5% of all meters
- WI 40.2 "
- CT 21.4 "
- KS 20.0 "
- ID 16.2 "

(3) According to the same FERC report, installed demand response programs in 2006 in the U.S. totalled about 37,000 MW or about 4% of total US peak demand. In comparison, Virginia utilities report only about 314 MW of load currently under control, or about 1½% of the system peak. Yet, the success of a Virginia cooperative utility, NOVEC, demonstrates that a far higher level of demand response programs is possible. In NOVEC, approximately 25% of its residential customers have peak limiting control systems installed.

(4) In a recent PJM day ahead auction for demand response in early August 2007, a total PJM peak of over 133,000MW was anticipated. Dominion Virginia Power contribution to the expected PJM peak demand was about 19,000MW. Almost 2000 MW of reduction was offered by large electricity users in the 13 states that are part of PJM's system, potentially reducing the PJM peak by 1½ %. However, contribution to peak reduction from users in Virginia totaled only 60MW[32] or only about 0.3% of Virginia's peak.

[31] FERC, Assessment of Demand Response and Advanced Metering, Staff Report, Aug. 2006. http://www.ferc.gov/legal/staff-reports/demand-response.pdf

[32] PJM presentation to Workgroup, Richmond, VA, August 23, 2007

(5) A 2006 study by the American Council for an Energy-Efficient Economy (ACEEE) compared utility expenditures for energy efficiency among the states. Virginia's utility expenditures were reported to be the lowest of all states.[33]

(6) The same 2006 ACEEE study ranked Virginia 38th among all states in its combined total scores in eight energy efficiency policy categories.[34]

The Virginia General Assembly, in 2007, recognizing the opportunity to reduce the need for future electric cost increases and to improve the utilization of energy in Virginia, enacted new legislation setting a goal for electricity usage reduction in the state, and encouraged efforts to explore the use of a variety of energy efficiency and demand management techniques.

In our situation of rising prices, rising demand and modest current participation in demand reduction programs, we have a major opportunity to implement effective programs and significantly limit the extreme costs of meeting high peak demand levels.

4. Impediments to Success: Stakeholder Perceptions

The Subgroup has compiled and reviewed several sources of information to identify impediments to demand response. These sources include:

- a 1991 SCC Staff Report entitled "Review of Commission Policy Toward Conservation and Load Management Programs;"
- a 2006 and a 2007 report on demand response, both prepared by the Federal Energy Regulatory Commission;[35]
- a July 2006 report entitled the National Action Plan for Energy Efficiency -- a plan developed by more than 50 leading agencies and organizations from the energy and environmental community and coordinated by the U.S. Environmental Protection Agency and the U.S. Department of Energy;
- a 2007 presentation on impediments developed by the PJM Demand Side Response Working Group; and
- a quick survey of impediments to demand response of concern to members of the Subgroup representing utilities and curtailment service providers.

The impediments identified by all these sources paralleled each other in many respects. A compilation of these inputs is provided below:

[33] Eldridge, M., et al, *The State Energy Efficiency Scorecard for 2006*, ACEEE Report #U054, 2007. Table 1.2, pp. 8-9.
[34] Id., Table ES-1, pp. iv-v.
[35] U.S. Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering,* August 2006, pp. xi-xii and 71-75. See http://www.ferc.gov/legal/staff-reports/demand-response.pdf

A. Lack of Perceived Need for Demand Response:

- The traditional focus of the utility industry in Virginia has been on supply-side solutions to address peak demand rather than on demand-side approaches. There has been no legislative or regulatory direction to achieve demand response specifically during critical peak times.
- Demand-side management in Virginia has generally utilized TOU and demand based rates, except for a small number of large commercial and industrial users on interruptible rates and a NOVEC program for air conditioner cycling. The TOU rates are based on *long TOU periods* (over two thousand hours per year). For example, under Dominion's Schedule 1S for residential customers, the on-peak period is eleven hours daily all summer and eight hours daily for the rest of the year (five days a week). The critical congestion periods amount to less than a hundred hours a year. The ISOs and/or regulatory authorities, not the local utilities, have driven the expansion of demand response on a real-time or near real-time basis.
- Lack of recent serious reliability failures masks the urgency of creating effective demand response programs for the future.
- If the emerging demand response programs at the regional wholesale level achieve progress in reducing the large price surges now encountered at critical peak times, the interest of parties in rewarding demand response may diminish.

B. Issues Involving Incentives and Cost Recovery:

- Virginia law provides incentives for generation expansion that do not apply to demand response expansion.
- Traditional approaches for cost recovery provide for inadequate recovery of the direct costs of demand-side programs.
- Most utilities earn profits based on the volume of electricity sold, thereby discouraging utility involvement in demand-side management programs that result in lost revenues. Some states are moving toward decoupling of revenues from kWh sales to address this conflict.
- Delays encountered by utilities in obtaining timely adjustments to rates/prices (e.g., rate caps, inability to make rate revisions outside of rate cases) discourage demand-side program investments;
- Utilities are reluctant to undertake investments in enabling technologies, such as advanced metering, unless the business case and regulatory support for deployment is sufficiently positive to justify the outlay;
- In ISO/RTO markets, there is delayed processing and disbursement of payments for demand reductions to participating retail customers. ISOs typically wait 60 days or more to finalize settlements. This delay creates cash flow problems for customers and curtailment service providers.
- Some Virginia utilities are resistant to demand response because of concern that the structure of the PJM program can result in DR payments above their actual value, resulting in potential adverse cost impacts to the utility and non-participating customers.

C. Institutional and Infrastructure Barriers:

- Fragmentation in the industry and government regulatory oversight.
- The demand response issue is multi-layered, with the legislature, PJM, the SCC, other state agencies, the utilities, and the CSPs, all seeking to work out policies, programs, and procedures to benefit the electricity industry and ultimately the consumer. In the meantime, there is confusion and a reluctance of consumers to participate.
- Better coordination is needed between FERC and State agencies. While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed.
- CSPs are able to bid in the wholesale market to provide MWs of demand response when called for by PJM, but the ability of these companies to then market and deliver these MWs within Virginia is subject to State regulatory policy. This potentially decreases the motivation of CSPs to support DR deployment in Virginia. It creates confusion due to potential differences in operations between regions and jurisdictions in the Commonwealth. More importantly, it may result in lower response for DR in the PJM auction market for future energy supply for Virginia.
- Lack of standards*.* For manufacturers to design demand control enabling equipment that is intended for mass-market customer use, there is a need for a degree of harmonization of requirements within the utility industry. The goal is to allow development of a mass market for these products, expanded competition and lower unit cost. These differences involve a variety of factors, including but not limited to equipment functionality requirements, rate structures designed for demand response users, procedures for using distributed generation for demand response, signaling technology for emergency response and its relationship to metering and billing infrastructure. This would require utility, ISO and manufacturers' representatives to develop industry standards, such as the standards that have been established for electricity metering.
- Lack of consideration of societal benefits, including environmental benefits of most forms of demand response.
- DEQ requirements are viewed by users as difficult to navigate, making it hard for users to utilize customer owned, otherwise idle, generation capability during critical peak time.
- Concern about the potential economic and operational impact of demand response on industrial customers.
  - Industrial customers have expressed concern that mandatory programs from individual utilities could result in negative impacts in the short-term.
  - PJM demand response programs at the wholesale level are designed to be voluntary and should improve reliability and reduce cost to industrial consumers in the long run.
- The concentration of work required in the near-term recommended for the SCC by this report may require additional staffing resources.

D. Consumer Education and Usage Issues:

- Lack of customer awareness that programs do exist or how to use them effectively.
- Very few residential customers in Virginia have gained access to time-variant rates in Virginia. Although such rates have been offered by utilities in Virginia for decades, the vast majority of customers do not know they are available. Many residential customers who have sought such rate schedules have encountered obstacles, such as Virginia Power telephone support employees telling them that no such rates exist or that the customer is not eligible for them. Commercial and industrial customers are more familiar with TOU rates, but most do not understand their own rate or how to manage their usage under that rate. Very few are aware of dispatchable programs.
- Customers are suspicious of vendors and technology that are unfamiliar. Demand response enabling equipment and CSPs are generally unknown to Virginia consumers. There is no brand awareness. This information gap can substantially increase marketing cost for CSPs and utilities attempting to deploy new programs.
- Customer belief that insufficient incentives exist. Because of their different needs and knowledge levels of *how* to respond, as well as their varying *abilities* to respond, customers need targeted and ongoing training and education to help them understand how to increase their response to demand response programs. Customer price-responsiveness varies significantly by market segment among commercial and industrial users. The differences in customers' ability to respond at peak times and the degree to which they are able or willing to respond implies that policy-makers need to create a portfolio of dynamic pricing products from which customers can choose and offer different incentives to different types of customers.
- Customer inertia/desire for simplicity. Most customers (particularly residential and small business ones) will be resistant to programs if they require non-automated effort and if the basic design of the program is complicated. Focusing these educational efforts first on the largest customers will allow these customers to adequately assess the rewards and costs associated with participation in demand response programs. Experience in other states such as New York and California (which use some system benefit funds for consumer education) has shown that targeted customer education and training increases participation and response rates.
- Simplicity enhances success. Customers notified by various means about real-time prices and price spikes achieve better responses and are more satisfied with the programs than with long TOU programs. For example, a recent Southern California Edison test of Ambient Orbs, a device that glows green when the grid is underused and red during peak hours, resulted in customers reducing their peak-period energy use by 40%.
- Customer responses to well-designed, simple programs they perceive as fair are high: they want to stay in the programs, and felt they achieved savings and control. Experience suggests that customers especially like dynamic pricing programs that pair automated customer technologies. Customers with access to smarter appliances and energy management systems thought they became more

aware of their energy use and costs as well as how their routines at home and at work impact their energy use.

- Requirements for customer investments:
  - Customers may need a commitment for a utility to offer a rate or program for a period of time to receive their payback. Failure to perceive this commitment causes the investment to fail the return-on-investment test. However, utilities seek to balance this requirement with their interest in "timely rate revisions." There are over 7,000 Virginia Power customers on Schedule 1S, a demand based TOU rate, and most have purchased an energy management system to automate their response based on the pre-programmed times for on peak. The uncertainty of how Schedule 1S will evolve after rate caps are removed is adversely impacting the promotion of this technology to customers.
  - Current cost for enabling technology tends to be high because of the lack of "critical mass" for product development, bulk manufacturing and marketing costs.
  - Customers and load-serving entities often need new automation or control equipment or retrofits to existing equipment and appliances that will allow them to easily adjust consumption. Recent advances in controls, electronics, and communications have dramatically decreased the cost and increased the functionality of these energy management technologies. Greater saturation of advanced meters will support additional demand response, where economic and effective, but they are not a prerequisite to meaningful demand response. Existing interval meters can be effective.

E. Rate Design Issues:

- Existing time-of-use rate designs in Virginia are primarily based on long periods of TOU (thousand of hours per year). Options that provide adequate compensation for responding during emergency peaks are missing.
- New technologies are emerging that allow customers to respond to near-real time signals. Programs that exploit that new customer capability have generally not been deployed.
- New rate designs are perceived as being detrimental to non-participants and may create perceived free riders.
- The utility rate structure is based on average (embedded) costs whereas DSM payments and pricing options are primarily based on marginal costs. Unless cost allocation is worked through carefully, adversely impacted parties will oppose the outcome. PJM and the member utilities are currently working on these issues, and SCC oversight also must assure fair and reasonable rates. Research has demonstrated that as long as customers are convinced that utility-posted rates are fair and reflect actual system circumstances, and are based on competitive markets, they will accept them as the basis for time-varying rates.

F. Barriers to Providing Demand Response by Third Parties:

- The potential sunset of various demand response programs are a disincentive to demand response providers.
- Because third parties or customers often bear the risks of programs dependent upon enabling technologies, they need long-term regulatory assurance or long-term contracts in order to raise the capital needed to invest in enabling technology.
- Lack of third-party and customer access to data has been identified as a barrier to demand response.

G. Measurement and Verification Issues:

- The measurement of demand reductions associated with incentive-based demand response programs has proven to be a difficult and controversial problem, particularly for demand-bidding, emergency demand response, and capacity programs. The key measurement issue is how to calculate the level of consumption that would have occurred if the participant had not curtailed consumption, i.e., the customer baseline level. Once the customer baseline is determined, the level of reduction is calculated by subtracting the actual demand from the estimated baseline normal demand. Although there are a variety of means to estimate the baseline that are used by utilities and ISOs (typically involving an average of usage over several recent days), at least one Virginia utility has not yet been convinced that PJM has successfully addressed the potential for "gaming" of the system by customers with unpredictable loads. For example, a participant may bid into the market or state that they will curtail when they would already be shut down for the day.
- For the vast majority of users, current metering systems are not capable of accommodating real-time rate schedules and other DSM initiatives. Without the ability to measure consumption by varying times of day, it will be difficult to offer and conduct many incentive-based demand response programs and to measure any reductions. Many states are addressing this by the mass deployment of advanced meters, but expanded use of interval meters can also be useful.
- Lack of customer access to their own metered data;
- Lack of real-time communication system to interface with metering systems;
- Current billing systems for the vast majority of customers will require modification to accommodate DR billing.

H. Establishment of Cost-Effectiveness Tests:

- One of the key challenges for regulatory approval and review of demand response is the lack of an adopted method or consensus procedure for the evaluation and definition of cost-effectiveness. The cost-effectiveness tests that were developed to assess demand-side management in the 1980s and 1990s focus on avoided generation costs and are inadequate to capture the additional market and reliability benefits that demand response can bring to retail and wholesale markets at critical peak times. Several ISO/RTOs have attempted to evaluate the cost-effectiveness of demand response in their yearly evaluations, but there is no consistency among them.

- Utilities and non-participating customers are likely to oppose cost-effectiveness tests that result in rates to non-participants exceeding the rates resulting from a supply-side resource.

5. Programs/Action Recommendations

While the Bill directs the SCC to conduct a much needed investigation into demand-side measures, it does not provide enough specific direction or mandate specific actions that would overcome the major impediments to the development and implementation of cost-effective programs. In this section, we recommend actions that will spur immediate and short-term opportunities and lay the foundation for longer-term investment in demand-side resources by the utilities, third-party Curtailment Service Providers (CSPs) and electricity-consuming customers. We are not making judgments as to whether existing legislation or SCC rules and policies "allow" the utilities, the SCC or others to implement programs. Rather, we simply note that the existing collection of legislation, policies, practices and rules do not currently promote demand-side resources, and it is imperative that this change.

We believe that some of these recommendations may require either authorization or funding by the General Assembly. <u>For the items in the following list of actions that are identified as **Immediate**, we urge the SCC to address in its report to the General Assembly whether it supports these actions and, if so, to request legislation in the next session that will include any necessary authorization and funding for these actions beginning in June 2008.</u>

The recommendations have been identified to overcome the impediments identified in this report. Every specific impediment is not tied to a specific recommendation. Most recommendations serve to reduce many individual impediments. For that reason, some of the broad categories listed in the impediments section may not be included below, but they have been considered within the recommendations provided.

A. <u>General Recommendations:</u>

- Establish a quantified goal for DR (MW) separate from the goal for consumption reduction (MWh) and to be achieved by a specified time. Utility performance and the continued appropriateness of the specific level of the goal should be subject to periodic evaluation by the SCC. Utilities should have flexibility in determining how best to cost-effectively achieve the goal in their service territory. The SCC should be able to award incentives based on real results in utility performance. If a determination is made to allow CSPs to market PJM DR Programs directly to retail customers, allow the utilities to include MWs of DR delivered by CSPs in their service territory to be counted toward achievement of their DR goals. Consideration should be given to counting specific methods of achieving demand response toward renewable energy goals, when these methods can be demonstrated to be cleaner and less expensive than those currently defined as renewable. (***Immediate***)

- Continue collecting information from electricity service providers offering load management programs, special metering programs, special rate programs, etc. Collect specific information related to costs, customer incentives, penetration levels, measurement and verification methods or standards, impacts on peak demand, other benefits, and plans to continue or enhance such programs. Use information to prepare a DR Programs Report and periodically update it as a source document for programs to be considered. (***Immediate***)
- Provide education to members of the General Assembly and state agencies, including conducting legislative workshops, regarding the changes taking place in the electricity industry and the need for enabling legislation and policy. Require an annual report by the SCC to the General Assembly on DR, Consumption Reduction and Conservation. ***(Immediate)***
- Continue the Workgroup process, renamed the Virginia Energy Collaborative, to develop a Virginia Energy Action Plan. Continue to identify impediment to DR and to recommend actions to reduce them. ***(Immediate)***

B. Recommendations to Address the Lack of Perceived Need for Demand Response:

- Establish a statewide education effort on the Virginia Energy Plan, with the objective of creating broad consumer awareness of the importance of consumers actively participating by taking positive actions to be part of the solution. The Virginia Energy Plan explains that there are short-term costs associated with developing and deploying effective energy efficiency and demand response programs but that the long-term costs for all are lower. As PJM and local utilities achieve the needed levels of supply commitments in the years looking forward, coming from both generation and DR, the marginal cost for additional supply will decrease. We need to reach the point where supply exceeds demand to attain price reductions. ***(Immediate)***
- Require all utilities in Virginia to prepare demand response and demand management reports for review and approval by the SCC and to update them annually. ***(Immediate)***

C. Recommendations to Address Incentives and Cost Recovery

- Under current Virginia statute, the SCC is authorized to approve "pilot" programs. While a properly designed "pilot" can be useful and effective, it can also be wasteful if it is merely a substitute for a full-scale program when the enabling technology and market transformation issues have already been proven/resolved elsewhere. Authorization for immediate cost recovery should allow conversion of "pilots" to full-scale programs and should encourage other new DR programs, with full cost recovery of investment and ongoing expenses.
- The standards/rules for full cost recovery and return on investment should mirror those for utility investments in conventional power plants, including the recently enacted profit incentives for new generation. Consideration should be given to

allowing the utilities to earn an even higher profit on certain demand-side resources to recognize the difficult-to-quantify environmental attributes of those sources relative to conventional generation. Full cost recovery of prudently incurred costs is not sufficient to spur investment in demand response programs. To properly balance utility decisions to consider demand response as an alternative to peaking generation, they must have at least the same financial incentives for each. **(Immediate)**

- Authorize cost recovery effective 1 January 2008, prior to removal of rate caps, for utility costs associated with planning and executing demand response programs. **(Immediate)**
- Evaluate "decoupling" or variations of the same as are being implemented in other states.
- Evaluate implementation of a Technical Assistance Program (TAP) and Technical Incentive Program (TIP), similar to that being used successfully elsewhere. The TAP provides compensation for consumers for the costs of engineering analysis to identify potential demand response actions, and the TIP subsidizes the cost for purchase and installation of enabling technology.

D. <u>Recommendations to Address Institutional and Infrastructure Barriers</u>

- Evaluate the appropriate role for the SCC in the emerging PJM system, working with regulatory bodies of other states within the PJM footprint, to achieve regulatory consistency similar to the consistency being developed within the industry for states with regulated retail markets. The intent of this effort should be to support and encourage the demand response programs of PJM and the local utilities, ancillary service, TOU and peak load interruption programs, including increased use of interval meters and of automated energy management systems. Within the PJM Demand Side Response Working Group process, the issues of cost effectiveness and the appropriate price for wholesale DR, the necessary metering and validation requirement, and many other similar issues addressed in the impediments section are being negotiated within the industry.
- We recommend that the SCC review the activities of CSPs in other states and develop consistent policies for their role in Virginia that would be applicable to all Virginia utilities. The objective should be to set policies that best achieve an aggressive program for deploying cost-effective DR throughout the state. **(Immediate)**
- Establish the policy that measurement and verification of load shedding by residential and small commercial customers can be established via statistically rigorous sampling and that comprehensive AMI deployment need not precede DR programs for this class of customers. **(Immediate)**
- Evaluate deployment of an AMI throughout all or part of the state. It should be viewed as an option to enhance opportunities for communicating prices to customers in real or near real time, accelerating measurement and verification of demand changes, and facilitating faster data processing and settlement. Additional opportunities would be available with a "smart grid", which encompasses not only AMI but provides additional capabilities and functionality.

- Evaluate alternatives for and deploy communications to customers on congestion in their area. Customers notified by various means about daily prices and price spikes achieve better responses and are more satisfied with the programs. Both in re-regulated electricity markets and traditional utility territories, multiple notification channels (such as toll-free numbers, pagers, cell phones, and the Internet) increase success rates of RTP programs. Customers' use of programmable communicating thermostats and other automated energy management devices is important for easier response to these rates. We envision that these capabilities and signals would be provided by utilities or CSPs, based on the deployment of rate options that allowed customers to benefit from their response actions taken.
- Implement strengthened building codes for all new and retrofitted building, requiring installation of load management/demand response equipment and controls as well as energy efficiency design features.
- Evaluate and act on the need for additional SCC staffing to implement the recommendation of this report.

E. Recommendations to Address Fragmentation in the Industry and Government Regulatory Oversight

- Include CSPs' participation in appropriate stakeholder processes of the SCC that impact on demand response within the state. Demand response programs are being designed and deployed by a combination of PJM and local utilities. A new aspect of this environment is the emergence of the CSP as agents to deploy these wholesale programs. The CSPs may be deploying a utility retail program or a PJM wholesale program and may become a point of contact with certain consumers. **(Immediate)**
- Establish a process within the SCC for ruling on conflicts involving utilities, CSPs or end use customers that believe the rules or policies of PJM and the utilities are adversely and unfairly impacting their ability to participate in these programs.
- Establish policies, supported by legislation where appropriate, that provide consistency and reasonable long-term certainty for programs to allow customers to make effective return on investment decisions. Allow the utilities to contract with CSPs under agreements with sufficient term lengths (10 years or more) to eradicate biases that exist for conventional generation.

F. Recommendations to Address Lack of Standards

- Establish a workgroup of stakeholders to develop, through a collaborative effort, standard rate designs (not the actual amount but the structure) that all utilities would be encouraged to offer as optional rate designs. We envision as few different structures as possible, recognizing that there are clear differences between customer classes. At least one rate within each class should be designed to accommodate customers willing to participate in dispatchable real-time or near-real time programs. A set of standard rates allows statewide education to consumers. It provides consistency to which enabling technology manufacturers can design. It also lowers marketing cost of utilities and CSPs in promoting specific programs because of the increased knowledge of consumers of the underlying principles and the dispelling of commonly held misconceptions.

- Establish policies that would encourage utilization of customer-owned generation, consistent with air quality goals, and simplify the process of using that source for critical peak demand response. There are significant levels of MWs available from this resource. As CSPs and utilities begin to market emergency and capacity programs to customers having such generation resources, it is important to be able to evaluate on the spot whether a specific prospect's resource fits whatever rules will apply. CSPs and utilities will be performing an engineering analysis of every prospect's facilities and should not have to go through a DEQ permitting process for every single analysis. Customers may be intimidated from pursuing this resource just to avoid such a process. The FERC has already established interconnection and net metering procedures for distributed generation. Virginia State agencies, including the Department of Environmental Quality, can decide what types of distributed generation it wishes to include under "demand response" for the purpose of meeting targets for peak reduction (MW), For instance, it may want to include or exclude based on size, operating hours limits, fuel type, or size relative to load "behind-the-fence". It is expected that the involved agencies would consider the Ozone Transport Commission's Memorandum of Understanding on the High Electric Demand Day Initiative, which is designed to reduce the use of backup generation with high emissions during peak demand periods. The agencies also may want to establish some other pre-defined limitations. The end result should be the ability to pre-approve situations that meet the rules established for this purpose.
- Provide sufficient flexibility to avoid the difficulties of implementing a "one-size-fits-all" approach to DR, such as treating a small apartment with one window A/C as being in the same class as a 5,000 square foot home with five A/C zones.
- The new market for DR products and services is likely to attract individuals and companies that fail to meet appropriate standards for ethics and performance. If a determination is made that CSPs can directly market certain PJM DR programs to retail customers, the SCC should consider licensing those CSPs similar to the process used for Competitive Service Providers in the Rules Governing Retail Access to Competitive Energy Services. As was the case for the initial licensing rules, the purpose is not to obstruct participation but to provide a means for the SCC to assess qualifications and to track complaints back to the offending company.

G. Recommendations to Address Lack of Consideration of Societal Benefits

- The Virginia Energy Plan recommends that societal benefits be considered in the valuation of DR. Existing legislation is inconsistent with this view. We recommend a proceeding, with participation by all stakeholders, to reevaluate this policy. (**Immediate**)

H. Recommendations to Address Concern About the Potential Economic and Operational Impact of Demand Response on Industrial Customers

- Allocations of cost for consumer education programs and other DR incentives should consider that electricity is a major business expense in Virginia and an important factor in location, expansion, and relocation decisions, while also recognizing that larger facilities are actually likely to be the primary initial benefactor of DR programs.

I. Recommendations to Address Consumer Education and Usage Issues

- Implement the Consumer Education Program recommended by the Information Subgroup. (**Immediate**)
- Promote participation in DR by all state-owned government buildings and facilities, encouraging use of the recently awarded contract for these and other energy efficiency services.
- When developing the Consumer Education Program, focus initial efforts on those areas that should have the largest and quickest payback, including the rapidly growing commercial sector.

J. Recommendations to Address Rate Design

- Evaluate the design of existing time-of-use rates to consider changes that would increase their effectiveness in reducing demand and their acceptance by consumers.
- The SCC should consider the potential cost impact of new rate designs on non-participants to determine if additional measures of protection for these customers are appropriate.
- Because of the immediate opportunity and urgency, most of the discussion focuses on the summer peak demand. However, all forecasts indicate that Virginia's winter peak is growing faster than the summer peak. High winter peaks can be as difficult to deal with as high summer peaks. Generation and delivery equipment ratings are typically slightly higher in the winter, but the public health and safety issues associated with supply scarcity or outages can be more serious than during the summer. To avoid capacity problems in the winter, programs would need to be designed to control space heating and water heating -- the primary drivers of winter peaks.

6. Impacts of Peak Demand Management

A. Introduction

The objective of this section is to discuss potential peak demand impacts resulting from DR programs. With the revival of DR programs over the past several years, there is quite a bit of research available from the Federal government, states with successful program and others, which could be used to prepare such an estimate. However, to create an estimate with a high level of confidence, it is essential to start with a baseline reflecting the factors that drive the current energy use patterns in Virginia. At a minimum, this would include the number and type of customers, saturation of electric end-use equipment and systems, and the expected evolution of these in the future. Customer and end-use load shapes and peak demand patterns would make the task much easier.

The legislation also asked that the recommended programs be cost-effective. The team had neither the data nor the resources to reach a conclusion on this matter. Unfortunately, there is no generally accepted methodology that can monetize ALL benefits and costs of DR. In the sections below, we provide illustrative examples of benefits and costs and discuss the issues involved in monetizing them.

However, notwithstanding current data limitations, the qualitative information assembled as part of this Subgroup’s effort, recent national studies conducted by the DOE and others, and successful programs implemented by leading states provide a strong argument for proceeding with peak demand reduction efforts on an expeditious basis in Virginia.

Given this body of work, a decision on a DR portfolio can be made. For example, methods like Integrated Resource Planning can help quantify the cost of DR compared to generation, transmission or distribution investment. In addition, impact on wholesale costs, which represent about one-half of the retail rates, can be estimated fairly readily by the regional transmission organization.

B. Published Estimates of Peak Demand Reduction Potential in Virginia

The team found two published estimates of Virginia’s demand reduction potential: one prepared by Summit Blue Consulting, the other in the 2007 Virginia Energy Plan.

- In a May 2007 report, Summit Blue Consulting states that:

  “a well-designed portfolio of DSM program offerings including both energy efficiency and demand response strategies could cost effectively reduce the Commonwealth's peak demand by approximately 5,000 MW and its energy consumption forecasts by 7,800 GWh over a ten-year planning horizon. These estimates represent nearly 17% of the Commonwealth's projected 2007 peak demand and nearly 10% of the Commonwealth's projected 2007 energy use. The estimates are well within the ranges

> presented in evaluations of DSM potential in other jurisdictions, and are likely conservative in that only basic DSM strategies were considered."[36]

Of the 17% demand reduction, Summit Blue attributes about 7.5% to cost-effective demand response programs.

- The 2007 Virginia Energy Plan estimates that conservation and efficiency programs could reduce the projected 2016 peak demand by about 14%,[37] which would be equivalent to almost 17% of the 2006 peak demand.

Unfortunately, neither report provides any quantitative information on the assumptions that led to their estimates.

The team did not have access to sufficient data or resources to develop a credible estimate of a feasible peak demand reduction or even whether such a reduction could be implemented within the time frame of the estimate. As recommended in Section 5 above, the Commonwealth should undertake and complete a study on an urgent basis to develop defensible demand reduction targets.

However, a lot of experience with DR programs has been accumulated over several decades that should be relied on by the SCC to expeditiously accomplish this objective. Some of the readily available data is presented below.

C. DR Reduction of End-Use Loads

In order to obtain an estimate of a system-level demand impact, it is necessary to understand the composition of the baseline demand. In simplified terms, the process then involves the following steps:

- Obtain/model end-use load shapes by customer segment
- Identify controllable end-use loads by segment
- Select technology for control and M&V
- Establish control strategy
- Estimate individual end-use load reductions
- Estimate total reductions and adjust for technology constraints

This section presents illustrative examples of data that is available to conduct the analysis of demand impacts.

[36] Summit Blue, *Conservation and Demand Response Opportunities in Virginia*, prepared for the Piedmont Environmental Council, May 2007. http://www.pecva.org/_downloads/longterm/Summit_Blue_Report.pdf

[37] State of Virginia. *The Virginia Energy Plan 2007*, Sept. 2007. See Table 2-4, page 40. http://www.governor.virginia.gov/TempContent/2007_VA_Energy_Plan-Full_Document.pdf

Data from a number of residential programs was summarized in a recent DOE report[38] (see Figure 2 below, along with the explanation reproduced from the report).

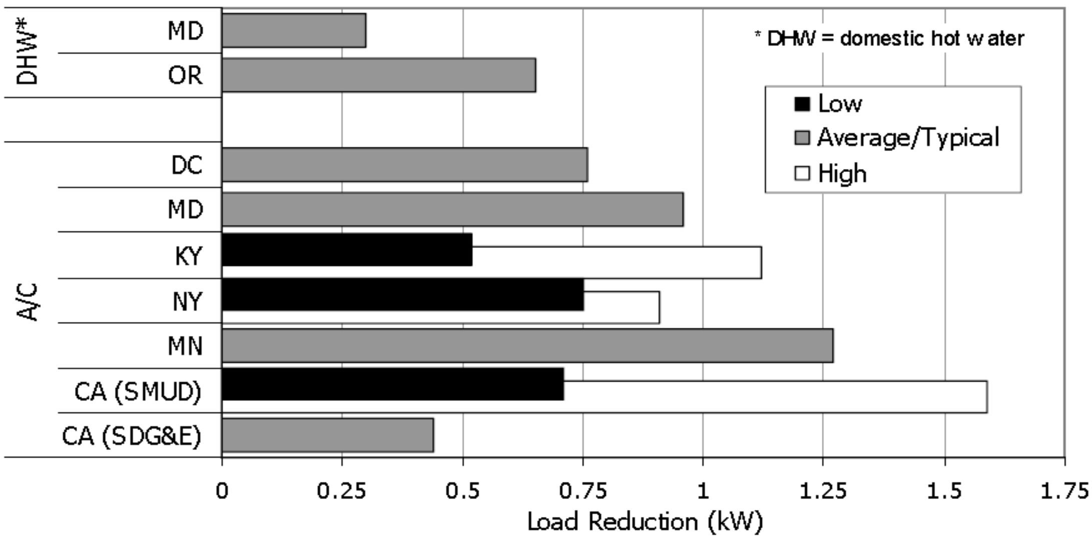


Figure 2. Estimated load impacts from residential DLC programs

> "Figure [2] summarizes reported load reduction estimates for large groups of customers with water heating load controls and various types of control strategies for air conditioning equipment (e.g., cycling the device on and off at a specified time interval, shutting the device off for a period of time, or resetting a thermostat set point. Residential water heating control programs have typically yielded load reductions in the range of 0.3 to 0.6 kW per house; the magnitude and timing of the load impact depends on household and equipment size, ground water temperature and household usage patterns. DLC programs targeting residential air conditioning (A/C) have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the control strategy deployed (e.g. 100% shed, duty cycling, thermostat reset) and the customer's air conditioning usage levels absent load control. This is illustrated in Figure [2] by several studies that reported low and high load reduction values based on testing different cycling strategies at various temperature levels".

[38] U.S. DOE, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, February 2006. Fig. 4-2, p. 34. http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

The same report also provides California data on commercial sector impacts, see Figure 3 below.[39]

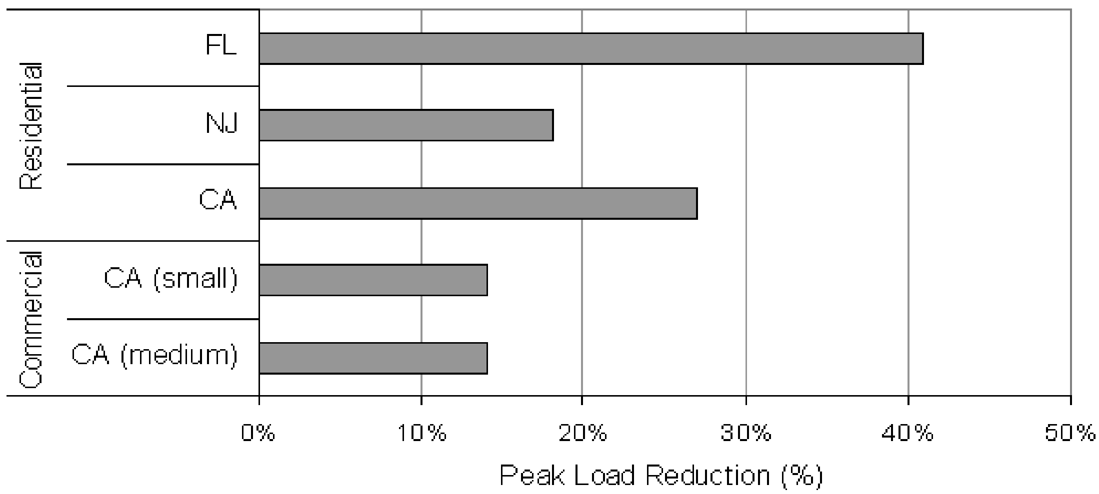


Figure 3. Response to Critical Peak Pricing and DR enabling technologies

Note, however, that the above data does not include potential DR contributions from other major loads, such as large commercial and industrial, agricultural and municipal pumping – all amenable to reliability dispatch. In fact, as shown in Figures 6 and 7 below, about one-half of the demand resources in place are attributable to these types of loads.

To understand and estimate demand response opportunities, one must understand the composition of the loads that contribute to the peak demand. For example, Figure 4 below shows the composition of the commercial demand during a peak day. The commercial load shape in Virginia would be very similar, except the cooling and refrigeration loads would be higher due to higher humidity (increased latent load) in this region.

As in all regions with high saturation of residential air conditioning, the Virginia summer peak is rather broad. From the load shape, we infer that it is driven primarily by commercial air conditioning and lighting during mid-afternoon (2-4 PM) and residential air conditioning during the early evening hours (5-7 PM). The residential and commercial air conditioning peaks are not coincident; therefore, both need to be addressed to achieve an impact that lasts for the duration of the system peak.

[39] Ibid, Figure 4-3, p. 35

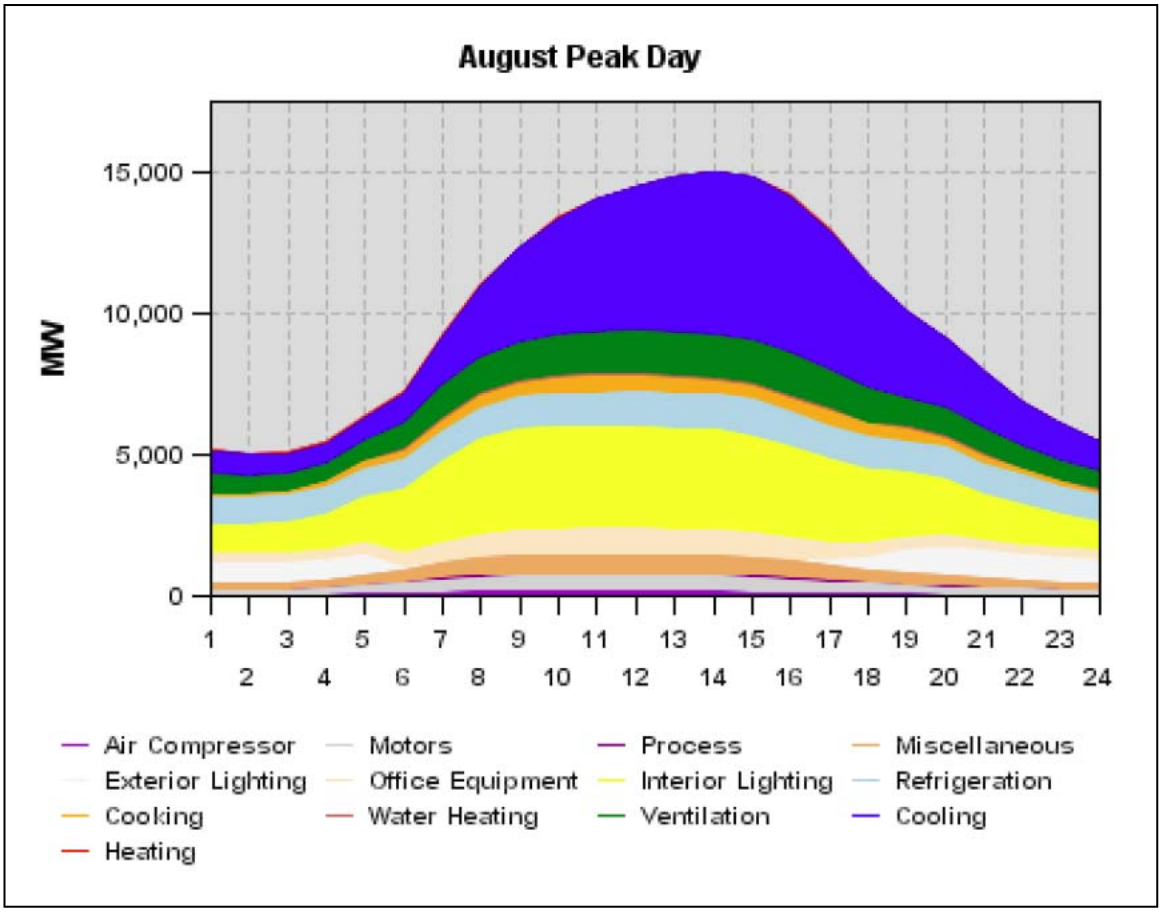


Figure 4. End-use load shape for a California commercial building[40]

An example of the impact of a load curtailment on an individual establishment is shown in Figure 5 below.[22] It is one of the small commercial establishments monitored in the Southern California Edison territory as part of the CPP pilot.

Equipment controlled in this pilot included:

- Lighting
- Walk-in coolers
- Walk-in freezers
- Reach-in coolers
- Commercial packaged air conditioners
- Ice makers
- Water heaters

The control system monitored temperatures for sensitive equipment, releasing the equipment from control if temperatures exceeded designated thresholds.

[40] Reproduced from http://capabilities.itron.com/CeusWeb/Chart.aspx

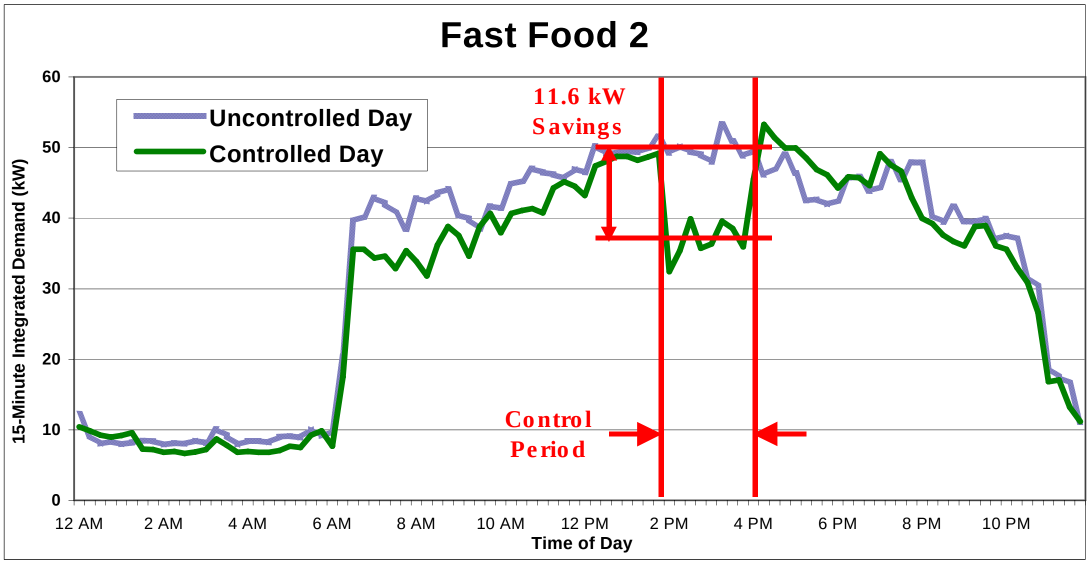


Figure 5. DR in a fast food establishment

This result is particularly interesting, because it is generally assumed that small businesses are very difficult to include in demand response programs. Note also that the "payback" (increase in demand that sometimes occurs after releasing control) is very small.

D. <u>DR capacity across the US</u>

In 2006, FERC published the results of a demand response and advanced metering survey.[41] One of the results of the survey was an estimate of 37,552 MW in US demand resources available for the 2006 summer peak. Figure 6, reproduced from the report,[42] shows the US peak demand reduction capacity by program type and customer class. The largest contribution comes from industrial interruptible/curtailable programs and residential direct load control programs. On the other hand, time-of-use rates, while available from most utilities, provide the smallest contribution. This is because few residential customers are aware of these rates, and many commercial customers (even though they are on the rate) don't (know how to) respond to the signals the rate provides – a situation similar to that in Virginia.

[41] FERC, *Assessment of Demand Response and Advanced Metering*, Aug. 2006. See also http://www.ferc.gov/industries/electric/indus-act/demand-response/charts-graphs.asp
[42] Ibid, Figure V-4, p. 83

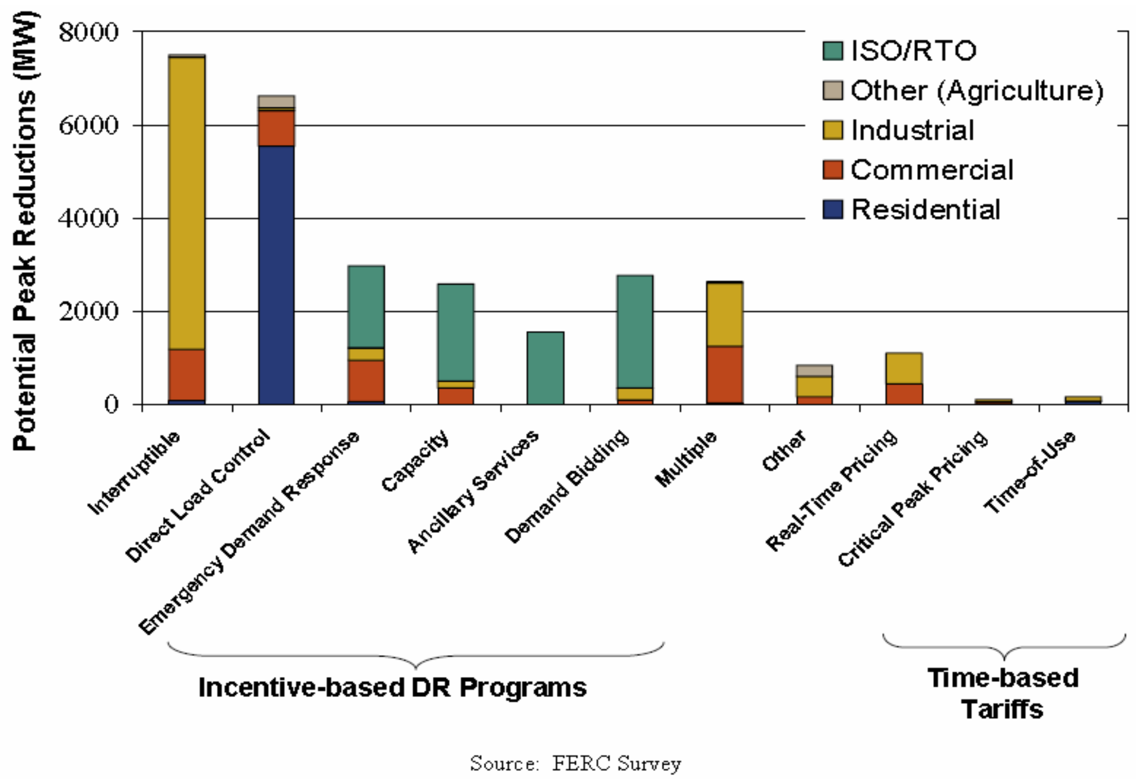
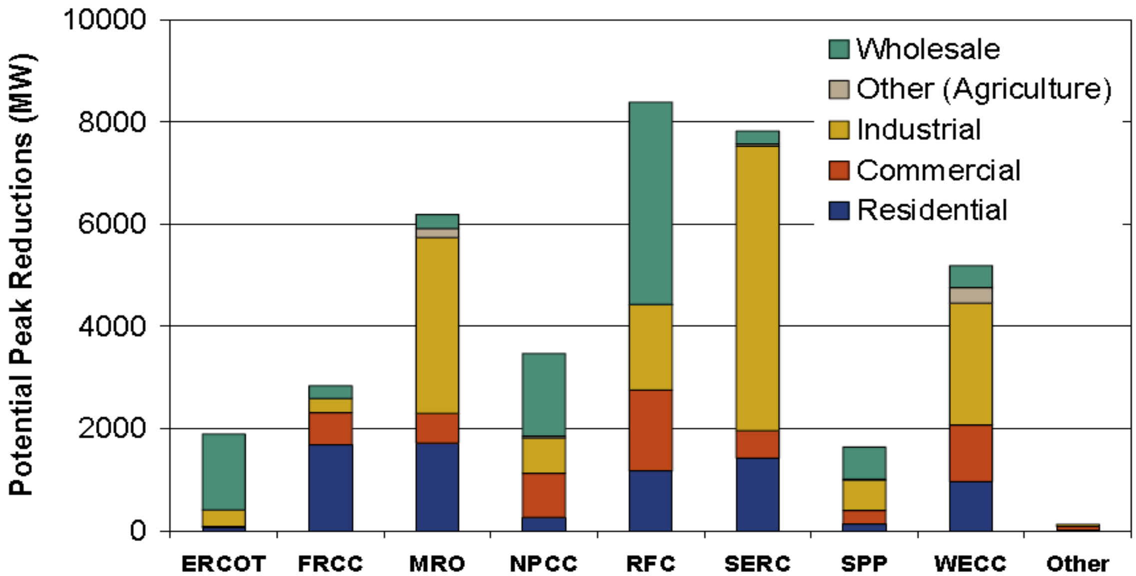


Figure 6. Resource potential of various types of demand response programs and time-based tariffs

Figure 7 below, also reproduced from the report,[43] shows the composition of demand resources as well as their impact on the summer peak for each reliability region. (Virginia is included under SERC.) Although the DR capacity is about 4-5% in most cases, MRO reports 20%. As FERC staff explains, the reason for this result is that several states (Minnesota and Iowa) in the MRO region currently have or previously had laws that required utilities to invest a certain percentage of revenues in demand-side management programs (1.5 to 2 percent), which contributed to demand response resource development. Utilities in this region have made significant investments in residential DLC programs, including both air conditioning and water heating programs. Second, utilities in the upper Midwest have historically had favorable rules that allowed load management resources to be counted towards meeting reserve requirements. Third, the characteristics of the customer base in the region, particularly among industrial customers, may be relatively more favorable to demand response resource development (e.g. steel plants and processes that can be interrupted). Utilities in the MRO region report that interruptible/curtailable tariffs are particularly popular among their large industrial customers.

[43] Ibid, Figure V-6, p. 87



	ERCOT	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
As Percent of Projected Summer 2006 Peak Demand	3%	7%	20%	6%	4%	5%	4%	4%	N/A

Source: FERC Survey
Notes: Other reliability region includes Alaska and Hawaii

Figure 7. FERC staff estimate of existing demand response resource contribution

We have not discussed demand reduction achievable from energy efficiency programs. A good summary of such data can be found in Table 2 of a recent ACEEE report.[44]

E. <u>DR Benefits</u>

During periods of peak demand, the wholesale price of electricity purchased by Virginia in the regional PJM electricity market has at times reached the price cap of $1,000/MWh (August 2007) – more than 17 times the average price of $57/MWh. Virginia customer participation in demand response (DR) programs could reduce this peak wholesale power cost. Moreover, with aggressive action to reduce peak electricity demand over the next decade, Virginia utilities may be able to save millions of dollars by deferring some of the expensive additions to generation, transmission and distribution resources.

In addition to capacity benefits, peak demand reduction also can improve distribution system efficiency. It is often assumed that most distribution benefits stem from deferral of capacity expansion. In fact, an immediate benefit from peak load reduction is a significant reduction in line losses. This result occurs because on-peak distribution system losses can be in the 12 to 15% range, compared to about 5% on the average.

[44] ACEEE. Examining the Peak Reduction Impacts of Energy Efficiency, Feb. 2007

◆ **Estimate of Gross Benefits**

There are many different ways to estimate the benefits from a demand response program. Most often, the approach taken includes only the specific types of benefits the program was designed to achieve. Unintended benefits may not be included in the valuation. The DOE report cited above[38] presents the results (see Fig. 4-4 of the report) of an effort to compare reported benefits on a uniform basis. A gross benefit metric was devised to normalize the study results, incorporating and adjusting for several factors: market size, time horizon, and the assumed level of customer participation in a demand response program or pricing initiative. The result is shown in Figure 8 below. (Note that $/kW shown in the figure are NOT avoided capacity costs, but $/kW of the total system peak.)

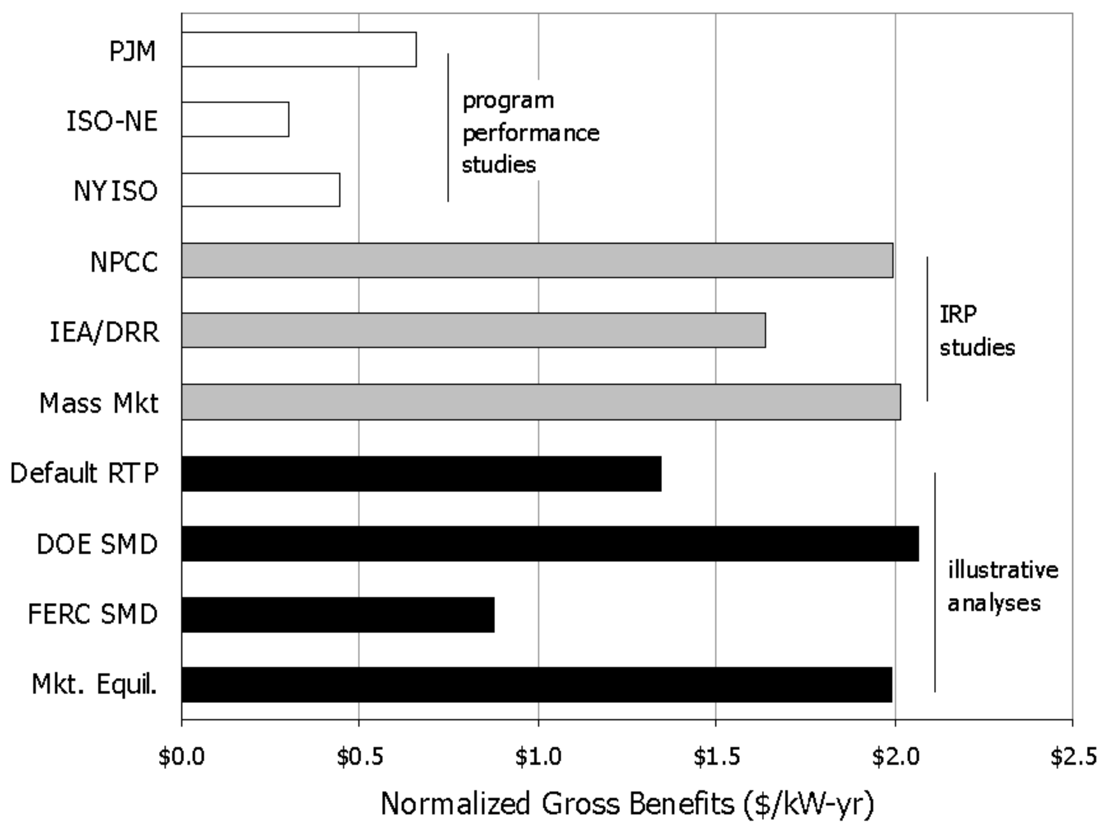


Figure 8. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

Benefits estimated from actual program performance appear to be much lower than those estimated in various studies. Apparently this is not due to poor program performance. Rather, much of the discrepancy is due to different valuation methods and different time horizons employed by the analyses.

The benefits range from 50¢ to $2 per peak kW per year. These figures would translate into gross savings to Virginia customers ranging from $16 million to $65 million in 2006 alone![45] This compares to an estimated total 2006 customer cost of electricity in Virginia of over $7 billion.

◆ **The Difference between PJM and State/Utility Program Benefits**

PJM has incorporated demand response both in reliability and in economic markets. The programs play an important role in: (1) ensuring reliability during capacity shortages (emergency response programs); and (2) moderating prices by permitting demand response to compete with available generation resources (economic programs). The benefits of the PJM programs include reduced wholesale power costs, reduced peak demands and capacity needs, and increased reliability of supply.

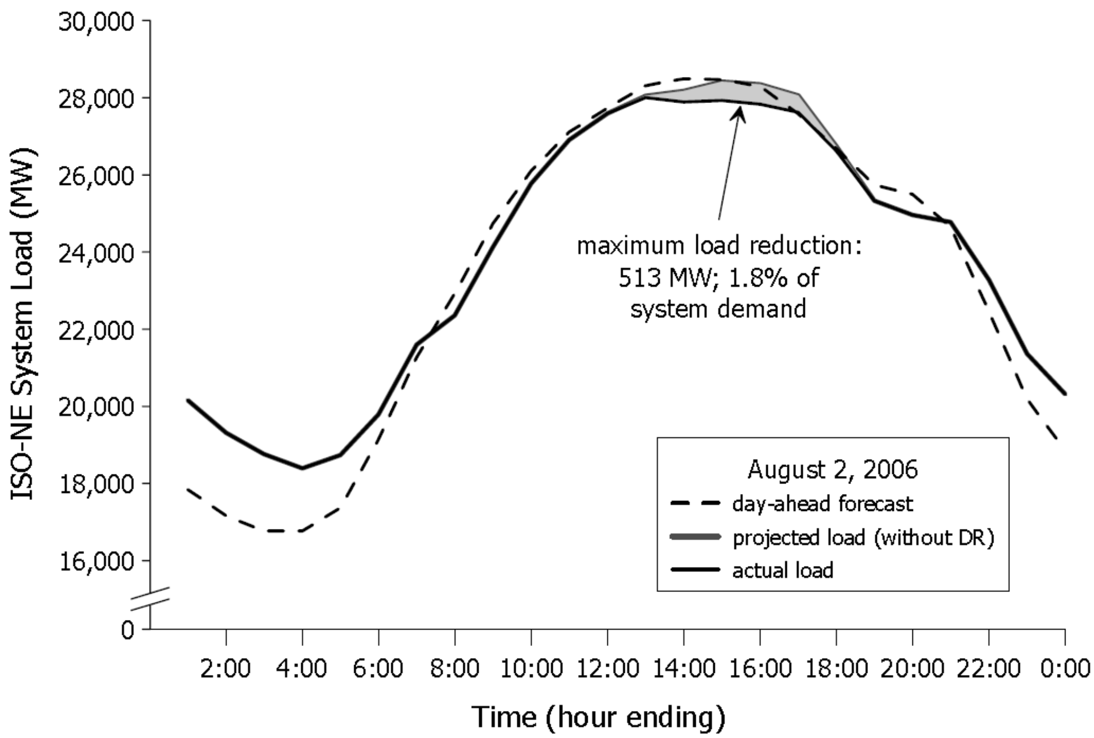
A specific example is provided in a recent report, which shows that a 3% reduction in peak demand can result in a 5-8% reduction of wholesale power costs during the 100 to 150 peak price hours[46]. (During the past year, the peak price period prices for Dominion Virginia Power (DOM zone of PJM) ranged from $200 to $1,000 per MWh.) The detailed breakdown of the savings to various stakeholders is shown in Table 1.

Table 1. Annual Benefits from 3% Load Reduction in the top 100 Hours in 5 MADRI[47] Zones

	Quantified Benefits in MADRI States	Quantified Benefits in Other PJM States	Unquantified Benefits	Caveats
Benefits to Non-Curtailed Load	$57-182 Million (energy only) (5-8% price reduction in curtailed hours)	$7-20 Million (energy only) (1-2% price reduction in curtailed hours)	• Capacity price decrease due to reduced demand; • Enhanced competitiveness in energy and capacity markets; • Real-time vs. day-ahead; • Value of reduced volatility; • Insurance against extreme events; • Avoided T&D costs.	• Probably significantly offset in long-run equilibrium as capacity and capacity prices adjust; "long-run" might not be so long. • Load shifting and demand elasticity offest some benefit in short-term.
Energy Benefits to Curtailed Load	$9-26 Million ($85-234/MWh price reduction in curtailed hours)	n/a	n/a	• Based on simplifying assumptions regarding the value of load that is curtailed.
Capacity Benefits to Curtailed Load	$73 Million (assuming $58/kW-Yr)	n/a	n/a	• Based on generic long-run cost of avoided capacity; • Ignores costs of equipment and DR program administration.
Total Annual Benefits	$138-281 Million	$7-20 Million	• Additional benefits to non-curtailed load could be large.	• Includes both the solid economic efficiency gains to curtailed load and the less robust benefits to non-curtailed loads.

45 Based on 2007 peak demand estimated in the 2007 Virginia Energy Plan
46 Brattle Group, *Quantifying Demand Response Benefits in PJM*, January 2007. http://www.energetics.com/madri/pdfs/BrattleGroupReport.pd
47 Mid-Atlantic Distributed Resources Initiative (MADRI) was established in 2004 by the public utility commissions of Delaware, the District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. DOE, U.S. EPA, FERC, and PJM.

Figure 9 below provides an example of how demand response can be dispatched to reduce the system peak. The figure shows the impact on ISO-NE load shape due to a reliability DR program.



Source: www.iso-ne.com, Yoshimura and Corcoran (2007)

Figure 9. Impact of Reliability DR Programs on ISO-NE System Load[48]

Although PJM has DR programs in place to ensure reliable grid operations, the PJM program does not provide an appropriate incentive to defer expensive additions of future generating, transmission, and distribution capacity. Because PJM cannot assure the availability of cost-effective future supply for Virginia, State and/or utility programs are needed to focus on the reduction of future peak demand growth and the attendant Virginia capacity needs. The 2007 Virginia Energy Plan estimates that absent any substantial effort to control the growth of the peak, an additional 5,100 MW of supply may be needed over the next decade. Currently, Virginia has only modest programs and related rate designs in place on the retail side.

[48] Reproduced from LBL, The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response, LBNL-62754, May 2007, Fig. 1. http://eetd.lbl.gov/ea/EMS/EMS_pubs.htm

F. Estimating Program Cost-Effectiveness

The cost/benefit measures used by the regulators in the past have been developed for energy efficiency programs and they do not account for the time-varying benefits of peak demand reduction programs. In addition, the current valuation framework does not capture the full range of DR costs and benefits and many other factors associated with implementation of DR in a deregulated environment. These include the inherent flexibility of DR, which manifests itself in a broad range of DR strategies and program options, the additional benefits that result from DR, the advent of new DR enabling technologies, and the presence of multiple stakeholders. While there are significant efforts aimed at its development, there is no acceptable methodology available today that can fully value DR.

Such a methodology has to be capable of taking into account the many different stakeholders and the value from their perspectives. For example:

- Participating customer value factors: e.g., financial (direct and indirect), comfort and convenience, transaction cost, service quality, product quality, and derived services [depending on the approach, these may include consumption data from energy management systems (EMS), equipment performance monitoring and diagnostics, web access, etc.]
- Non-participating customer value factors: financial (through rates), avoidance of blackouts or brownouts)
- Utility (distribution company) value factors, e.g., implementation costs,[49] revenue impacts; reserve requirements; timing, location, and persistence of impacts (including long-term resource impacts and/or forward curve); wholesale cost/ risk management; and distribution system costs, data, and controllability
- Power System/Transmission Grid value factors, e.g.,, as emergency control, flexibility in shaping the response, risk management, impact on merchant power suppliers, price stability, resource “equivalency”
- Environmental factors, e.g., impact on criteria pollutants and GHGs.

These factors are summarized in Table 2 below.

Many of these factors require development of a brand new metric. Past practice has placed emphasis on cost of service methodologies. Today, markets and reliability are the focus of the new thinking, and tomorrow an approach based on measuring consumer surplus and producer surplus may be desired. Examples of more difficult tangible and intangible valuation issues include customer flow-down benefits derived from any technology installed in conjunction with DR; value of information generated as part of the DR process; avoided costs of brownouts or blackouts; and value of flexibility and risk management. The eventual framework will have to be able to accommodate all of these factors and include a capability to reflect the current and future range of technology portfolios, capabilities, and associated impacts.

[49] Program marketing costs are often neglected or underestimated; in fact, even at a 10% penetration they can far exceed any equipment, installation, or incentive costs.

Table 2. How DR Values and Costs Might be Allocated

Perspectives	Customer	Utility	Power System	Environment
Derived Value	• Financial incentives • Reduced energy bills • Higher product quality • Better control • Better information • Improved comfort and productivity	• Avoided capacity costs • Avoided energy costs • Load information • Enhanced customer service • Reduced billing costs	• System reliability • Price stabilization • Avoided system expansion • Risk management • Market power mitigation	• Avoided criteria pollutants • Avoided GHGs
Potential Cost	• System automation • Labor • Loss of comfort • Loss of productivity	• Incentive payments • Lost revenues • Infrastructure development • Administratio n • Increased billing costs	• Incentive payments • Infrastructure development • Administration	• Increased emissions

7. Selected Reference Materials

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