ENERGIZING VIRGINIA: EFFICIENCY FIRST

American Council for an Energy-Efficient Economy
Summit Blue Consulting
ICF International
Synapse Energy Economics

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ABOUT THE AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE)

ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting economic prosperity, energy security, and environmental protection. For more information, see http://www.aceee.org. ACEEE fulfills its mission by:

- Conducting in-depth technical and policy assessments
- Advising policymakers and program managers
- Working collaboratively with businesses, public interest groups, and other organizations
- Organizing conferences and workshops
- Publishing books, conference proceedings, and reports
- Educating consumers and businesses

Projects are carried out by staff and selected energy efficiency experts from universities, national laboratories, and the private sector. Collaboration is key to ACEEE's success. We collaborate on projects and initiatives with dozens of organizations including federal and state agencies, utilities, research institutions, businesses, and public interest groups.

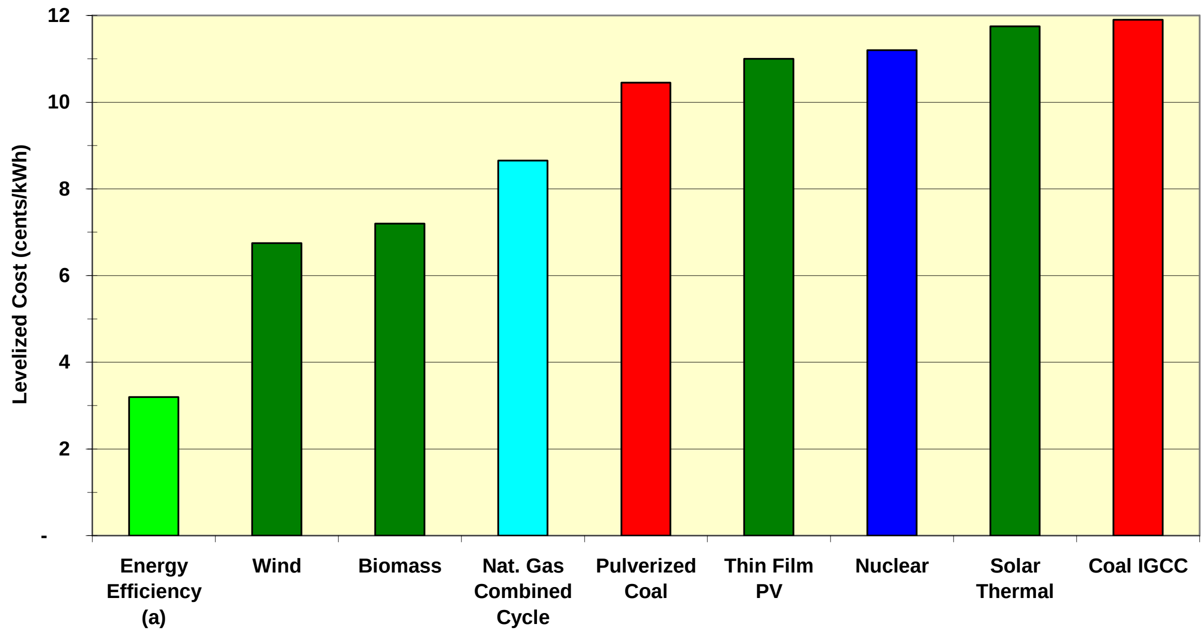
Support for our work comes from a broad range of foundations, governmental organizations, research institutes, utilities, and corporations.

EXECUTIVE SUMMARY

Over the past decade, the Commonwealth of Virginia has experienced a rapid increase in its demand for electricity due in large part to economic and population growth, particularly in Northern Virginia. This rapid increase in Virginia's demand for electricity could negatively impact the Commonwealth's future economic growth by causing further increases in utility prices and the potential for decreased reliability. Energy efficiency and demand response have the potential to moderate these impacts while at the same time improving the economic health of the Commonwealth.

Energy efficiency and demand response are the lowest-cost resources available to meet this growing demand and the quickest to deploy for near-term impacts (see Figure ES-1).

Figure ES-1. Estimates of Levelized Cost of New Energy Resources



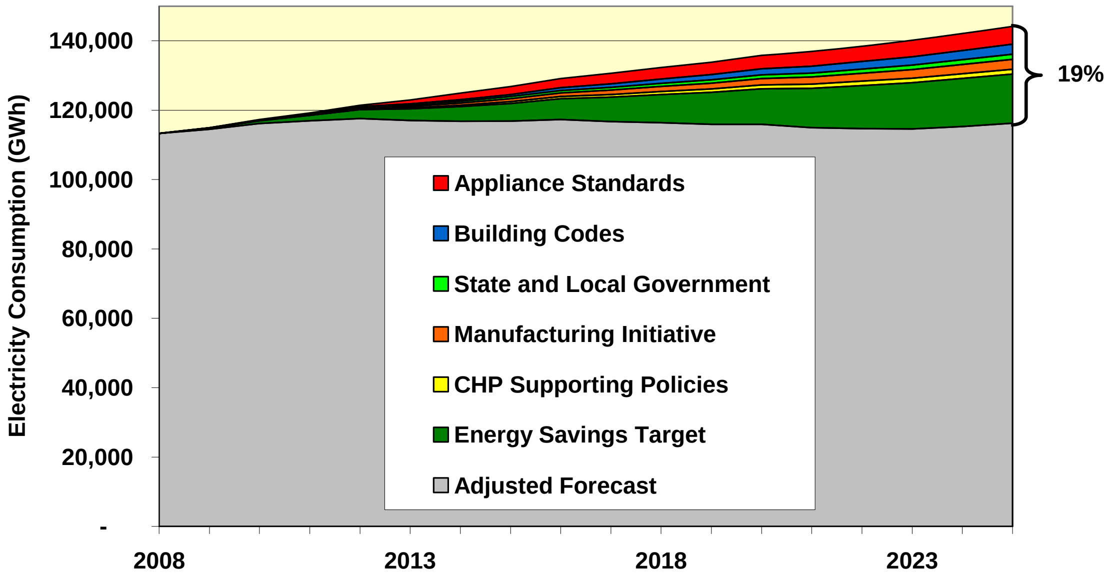
As can be seen in Figure ES-2, ACEEE estimates a suite of energy efficiency policies and programs that could save 10,000 GWh of electricity, or meet 8% of Virginia's electricity needs in 2015. By 2025, savings grow to 28,000 GWh, or 19% of Virginia's electricity needs in 2025, in our medium policy scenario.

Policy Recommendations

ACEEE suggests that policymakers consider the following suite of eleven policy recommendations:

1. Energy Efficiency Resource Standard (EERS)
2. Expanded Demand Response Initiatives
3. Combined Heat and Power (CHP) Supporting Policies
4. Manufacturing Initiative
5. State Facilities Initiative
6. Local Government Facilities Initiative
7. Building Energy Codes
8. Appliance and Equipment Efficiency Standards
9. Research, Development & Deployment (RD&D) Initiative
10. Consumer Education and Outreach
11. Low-Income Efficiency Programs

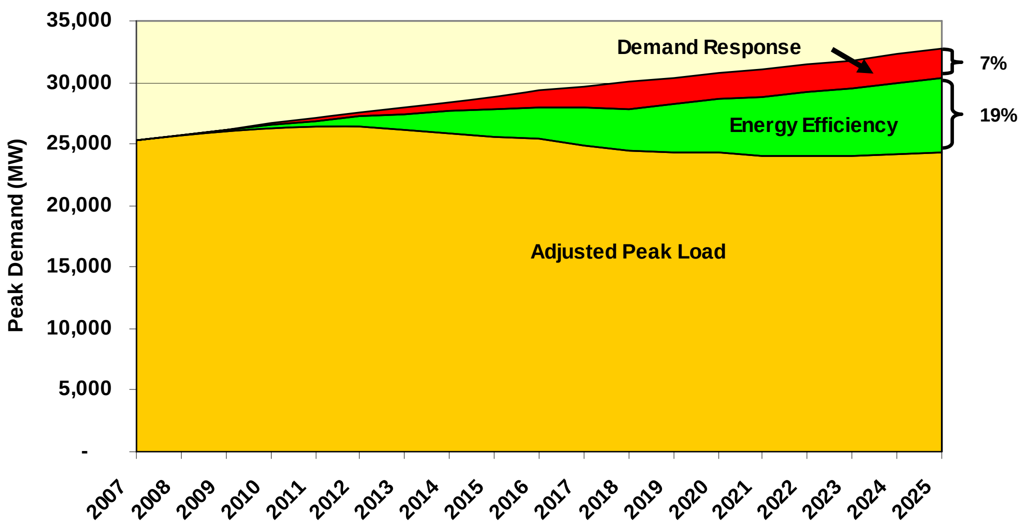
Figure ES-2. Share of Projected Electricity Use Met by Energy Efficiency Policies — Medium Scenario



These recommendations draw from the best practice policies currently implemented throughout the country. The EERS represents the core of these policies, providing a foundation upon which the manufacturing initiative, government facilities, appliance standards, and building codes can be layered to fully achieve the goals. Energy efficiency can also reduce peak demand in Virginia, which occurs during the summer on days when electricity needs are highest (see Figure ES-3).

In addition, we find that a suite of demand response (DR) recommendations, which focuses on shifting energy from peak periods to off-peak periods and cutting back electricity needs on days with the highest needs, is a critical component of reducing peak demand in Virginia. Figure ES-3 presents the combined effects of energy efficiency and demand response on peak reductions in a medium case policy scenario.

Figure ES-3. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response — Medium Scenario (2025 peak reduction = 8,400 MW, or 26%)



ACEEE also considered a more aggressive suite of policies that would increase energy savings to 39,000 GWh in 2025, meeting 27% of Virginia's electricity needs in that year. Combined, the high scenario suite of energy efficiency policies plus the potential for demand response can reduce peak demand by nearly 11,000 MW in 2025, or a 36% reduction in peak demand.

Economic and Jobs Impacts

The energy savings from these efficiency policies can cut the electricity bills of customers by a net $500 million in 2015. Net annual savings grow nearly five-fold to $2.2 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach $15 billion. To put this into context, an average household will save a net $5 on its monthly electricity bill by 2015 and $20 per month by 2025. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Investments in efficiency have the additional benefit of creating new, high-quality "green-collar" jobs in the Commonwealth and increasing both wages and Gross State Product (GSP). Our analysis shows that energy efficiency investments can create nearly 10,000 new jobs in Virginia by 2025 (see Table ES-1), including well-paying trade and professional jobs needed to design and install energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to almost 100 new manufacturing plants relocating to Virginia, but without the public costs for infrastructure or the environmental impacts of new facilities.

Table ES-1. Economic Impact of Energy Efficiency Investments in Virginia

Macroeconomic Impacts	2015	2025
Jobs (Actual)	675	9,820
Wages (Million $2006)	63	583
GSP (Million $2006)	202	882

Conclusions

The Commonwealth of Virginia finds itself at a juncture with respect to its energy future. The state can either continue to depend solely upon conventional energy resource technologies to meet its growing needs for electric power as it has for more than a century, or it can chose to slow—or even reduce—future demand for electricity by investing in energy efficiency and demand response. As this assessment documents, there are plenty of cost-effective energy efficiency and demand response opportunities in the state. However, as this report also discusses, these opportunities will not be realized without changes in policies and programs in the state. We suggest a wide array of energy efficiency and demand response policies and programs that have proven successful in the past, and can meet 90% of the increase in the state's electricity needs over the next 18 years, and 120% of the increase in peak demand. These policies and programs are already proving themselves in other states, delivering efficiency resources and reducing consumer electric expenditures. **And**, these policy and programs can accomplish this at a lower cost than building new generation and transmission, while at the same time creating nearly 10,000 new, high-quality "green collar" jobs by 2025.

These policy and program suggestions should not be viewed as prescriptive, but as the starting point for a dialog among stakeholders on how to realize the efficiency resource that is available to the state. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically plausible in the state. Clearly there are other policies and programs, some of which we suggest in our aggressive scenario, which could be implemented to realize even more of the available energy efficiency resource.

Also, we do not suggest that these recommendations will meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource that is available near term and that can make an important contribution in the longer term, the state will need additional resources to meet the remainder of the new load and to replace older, dirtier power plants in the coming years. Most importantly, energy efficiency can buy time for a robust discussion about what other resource choices—both conventional and alternative—the state makes in the future.

Glossary

ENERGY POLICY AND ORGANIZATIONS

(ASHRAE) American Society of Heating, Refrigerating and Air-Conditioning Engineers: Organization of over 50,000 professionals in the air-conditioning, heating, refrigerating and ventilating fields. Support the integration of increased energy efficiency in building design via technological enhancements of these systems (http://www.ashrae.org/).

Avoided Costs: The marginal costs incurred by utilities for additional electric supply resources. Used by utilities to evaluate the cost-effectiveness of energy efficiency programs.

(EERS) Energy Efficiency Resource Standard: A simple, market-based mechanism to encourage more efficient generation, transmission, and use of electricity and natural gas. An EERS consists of electric and/or gas energy savings targets for utilities. All EERS include end-user energy saving improvements that are aided and documented by utilities or other program operators. Often used in conjunction with a Renewable Portfolio Standard (RPS). (See ACEEE's fact sheet for state details: http://aceee.org/energy/ state/policies/2pgEERS.pdf.)

(EISA 2007) Energy Independence and Security Act of 2007: Law covering issues from fuel economy standards for cars and trucks to renewable fuel and electricity to training programs for a "green collar" workforce to the first federal mandatory efficiency standards for appliances and lighting.

ENERGY STAR®: A joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy helping residential customers save money and protect the environment through energy-efficient products and practices (http://www.energystar.gov/). Includes appliance efficiency standards and new building codes.

(EPAct) Energy Policy Act: Law directing U.S. energy policy; first passed in 1992 and major revisions were passed in 2005 and 2007.

(ESCO) Energy Service Company: Provides designs and implementation of energy savings projects. The ESCO performs an in-depth analysis of the property, designs an energy-efficient solution, installs the required elements, and maintains the system to ensure energy savings.

(ESPC) **Energy Service Performance Contracting:** A financing technique that uses cost savings from reduced energy consumption to repay ESCO's (see above) for the cost of installing energy conservation measures and other services.

(FEMP) Federal Energy Management Program: U.S. Department of Energy program "works to reduce the cost and environmental impact of the Federal government by advancing energy efficiency and water conservation, promoting the use of distributed and renewable energy, and improving utility management decisions at Federal sites" (http://www1.eere.energy.gov/femp/about/index.html).

(FERC) Federal Energy Regulation Commission: Federal agency that "regulates and oversees energy industries in the economic, environmental, and safety interests of the American public" (www.ferc.org).

(IRP) Integrated Resource Plan: A comprehensive and systematic blueprint developed by a supplier, distributor, or end-user of energy who has evaluated demand-side and supply-side resource options and economic parameters and determined which options will best help them meet their energy goals at the lowest reasonable energy, environmental, and societal cost (http://www.energycentral.com/ centers/knowledge/glossary/home.cfm).

(LIHEAP) **Low-Income Home Energy Assistance Program**: A federally funded program intended to assist low-income households that pay a high proportion of household income for home energy, primarily in meeting their immediate home energy needs.

(NERC) North American Electric Reliability Corporation: NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada (www.nerc.com).

GENERAL REPORT TERMINOLOGY

Additionality: A framework for evaluating whether projects are deserving of offset credits in climate change mitigation strategies. If a project would have been undertaken and financially attractive regardless of incentives of any kind, then offering incentives to the project is said to yield no "additionality." The standard thinking is that financial incentives/offset credits should be offered only to projects that would not have happened *but for* the offering of credits.

Cumulative Savings: Sum of the total annual energy savings over a certain time frame.

Demand Side Management (DSM): Programs that focus on minimizing energy demand by influencing the quantity and use-patterns of energy consumption by end users, as opposed to supply side management, which focuses on investments in system infrastructure.

Energy Efficiency: The implementation of programs and policies that minimize the consumption of energy resources while stimulating economic growth.

Incremental Annual Savings: Energy savings occurring in a single year from the current year programs and policies only.

Percent Turnover: Percentage of technology replaced on burnout with more efficient technology. Does not include retrofits.

Potential: amount of energy savings possible

- **Achievable Potential**: Potential that could be achieved through normal market forces, new state building codes, equipment efficiency, and utility energy efficiency programs
- **Economic Potential**: Potential based on both the Technical Potential and economic considerations (e.g., system cost, avoided cost of energy)
- **Technical Potential:** Potential based on technological limitations only (no economic or other considerations)

Replace-on-Burnout: The act of waiting until a technology's end of life before replacing it with a more energy-efficient technology. Cost basis is the incremental cost of choosing a more efficient technology over a less efficient one. Incremental cost usually means incremental equipment cost with no labor cost; that is, there is no labor cost or it is the same in both cases and thus a zero-sum.

Retrofit Measure: The act of replacing a technology with a more energy-efficient technology before its end of life. Cost basis is the full cost of the new technology, including installation.

Total Annual Savings: Energy savings occurring in a single year from the current year programs and policies and counting prior year savings. Sum of all Incremental Annual Savings.

INDUSTRY and BUILDINGS TECHNOLOGY

(CHP) Combined Heat and Power: method of using waste heat from electrical generation to offset traditional process or space heating. Also called cogeneration (cogen).

Electricity Use Feedback: System that monitors home/building electricity use and provides real time feedback to occupants. This allows occupants to increase energy efficiency.

ENERGY STAR® New Homes: 15% electricity savings over a comparable size home.

HVAC: Heating, ventilation, and air conditioning system.

(NAICS) **North American Industry Classification System**: 6-digit code used to group industries by product.

UTILITY TERMS

Coincidental Peak: The sum of two or more peak loads that occur in the same time interval.

Coincidental Peak Factor: The ratio of annual peak demand savings (kW) from an energy efficiency measure to the annual energy savings (kWh) from the measure; also called Coincidence Factor.

Demand Response: The reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling.

Deregulation: Allows a rate payer to choose other electricity providers over a local provider. Deregulation efforts vary from reducing to completely eliminating a local monopoly on electricity.

Distributed Energy Resource: Electrical power generation or storage located at or near the point of use, as well as demand-side measures

Distributed Generation: Electric power generation located at or near the point of use.

Distributed Power: Electrical power generation or storage located at or near the point of use.

Electricity Distribution: Regulating voltage to usable levels and distributing electricity to end-users from substations

Electricity Generation: Converting a primary fuel source (e.g., coal, natural gas, or wind) into electricity.

Electricity Transmission: Transport of electricity from the generation source to a distribution substation, usually via power lines.

Henry Hub: The market price for natural gas is by convention set at the Henry Hub (which is a physical location in southern Louisiana where a number of pipelines from the Gulf of Mexico originate). Futures and spot market contracts for delivery of gas are traded on the New York Mercantile Exchange (NYMEX) with regional wholesale prices set at key hubs where pipelines originate or come together. These prices are set relative to the Henry Hub price with adders for transportation and congestion.

(IOU) Investor-Owned Utility: Also known as a private utility, IOU's are utilities owned by investors or shareholders. IOU's can be listed on public stock exchanges.

(ISO) Independent System Operator: Entity that controls and administers nondiscriminatory access to electric transmission in a region or across several systems, independent from the owners of facilities.

Levelized Cost: The level of payment necessary each year to recover the total investment and interest payments at a specified interest rate over the life of the measure.

Peak Demand: The highest level of electricity demand in the state measured in megawatts (MW) during the year.

Peak Shaving: Technologies or programs that reduce electricity demand only during peak periods (frequently combined with "valley filling" policies that shift consumption to periods of low demand. The combination is referred to as load shifting.)

PJM: PJM Interconnection is a Regional Transmission Organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Power Pool: Two or more inter-connected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Renewable Generation: Electric power generation from a renewable energy source such as wind, solar, sustainably harvested biomass, or geothermal.

(RTO) Regional Transmission Organization: An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size. Controls and manages the transmission and flow of electricity over large areas.

(REC) Rural Electric Cooperative: REC's are nonprofit, cooperative utilities that provide electricity to rural areas and are owned by all customers of that utility.

Transformer: Electrical device that changes the voltage in AC circuits from high-voltage transmission lines to low voltage distribution lines.

Wholesale Competition: A system in which a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Electricity: Power that is bought and sold among utilities, non-utility generators, and other wholesale entities, such as municipalities.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

INTRODUCTION

Over the past decade, the Commonwealth of Virginia has experienced a rapid increase in its demand for electricity. Significant economic and population growth has been a primary driver of this rise in demand, particularly in the Northern Virginia region, which has historically been home to two of the fastest growing counties in the nation.[1] The impact of population growth on electricity demand is compounded by the fact that electricity consumption per customer has risen dramatically in the past several decades. Today the average residential customer consumes in Virginia about 14,000 kWh per year, 25% more than the national average, and the average commercial customer uses 50% more electricity than it did in 1990 (EIA 2007b). This rapid increase in Virginia's demand for electricity could impact the Commonwealth's future economic growth. As demand outstrips electric supplies, the added strain on the grid during peak times, particularly in Northern Virginia could result in reliability problems as early as 2011 (DMME 2007), and result in price increases and greater price volatility. As this report will demonstrate, energy efficiency and demand response have the potential to moderate these impacts while simultaneously improving the economic health of the Commonwealth.

Energy efficiency and demand response are the least-cost resources available to meet this growing demand and the quickest to deploy for near-term impacts. While energy efficiency focuses on reducing overall electricity consumption, demand response is essential to reducing electric load at those peak times of Virginia's electricity needs. Not only is demand for electricity growing in the Commonwealth, but rapidly increasing fuel and electricity prices are being felt by consumers and straining household budgets. Recently, an 18% electricity rate increase was approved for Dominion Virginia to recover rising fuel costs (SCC 2008a) and Appalachian Power (APCo) has similarly requested an increase in its fuel rate. Both price increases are in advance of rate caps coming off in December of 2008, which are expected to further raise prices. Unlike supply-side energy resources, efficiency and demand response are the only resources that can actually begin to *reduce* customer electric bills by reducing overall consumption. These clean energy resources are not only important to consumers and electric reliability in the Commonwealth, but they also can be vital to the economy. Investing in efficiency also creates new "green collar" jobs in fields such as construction and technology development and deployment.

A growing consensus is emerging that the Commonwealth must do more to realize this clean energy resource. And because the energy policy choices Virginia makes now will define its energy future for years to come, it is important that policymakers and consumers be aware of the policy options available to them.

The goal of this study is to inform policymakers and stakeholders of the opportunities for energy efficiency and demand response in Virginia, and to suggest policies the Commonwealth could implement to tap into these clean energy resources. Our results are designed to help educate policymakers and the public at large about the importance of energy efficiency and demand response, and to facilitate policy development in Virginia for the next several years by identifying policy and technical opportunities for achieving major energy efficiency savings and benefits.

This report is organized into the following sections:

- ***Background:*** *Reviews the electricity market in Virginia, including recent actions and future opportunities regarding energy efficiency and demand response.*

- ***Project Overview and Methodology:*** *Provides a context for ACEEE's work with state-level energy efficiency and demand response potential studies and an overview of both the project approach and analysis methodology.*

[1] Loudoun County and Prince William County (DMME 2007).

- ***Reference Case:*** *Discusses the reference case electricity, peak demand, and price forecasts used in this analysis.*

- ***Energy Efficiency Resource Assessment:*** *Estimates the cost-effective potential, from the customer's perspective, for increased energy efficiency in the state's residential, commercial, and industrial sectors by 2025 through the adoption of specific energy-efficient technology measures. The resource assessment goes beyond what the state can achieve through penetration of specific programs and policies.*

- ***Energy Efficiency Policy Analysis:*** *Outlines the recommended policies for Virginia to adopt to tap into the energy efficiency resource potential. This section presents the electricity and peak demand impacts from energy efficiency, the associated costs, and an evaluation of program costs using two cost-effectiveness tests (TRC and the Participant cost tests). Also included in this section is an estimation of carbon dioxide emissions impacts.*

- ***Demand Response Analysis:*** *Estimates the potential for increased demand response in Virginia and makes specific recommendations to the Commonwealth.*

- ***Macroeconomic Impacts:*** *Estimates the impact of energy efficiency policies on Virginia's economy, employment, and energy prices.*

BACKGROUND

Virginia Electricity Market

The Commonwealth of Virginia briefly experimented with utility deregulation starting in 1999, but the competition that deregulation was expected to create failed to materialize. Legislation introduced in 2007 ended the state's commitment to deregulation, although the replacement system offered a "hybrid" alternative to the regulation that existed prior to 1999. Through this system, utilities are still subject to rate caps but are also guaranteed a rate of return, allowing them to borrow money in order to finance projects such as building new capacity to meet demand (DMME 2007).

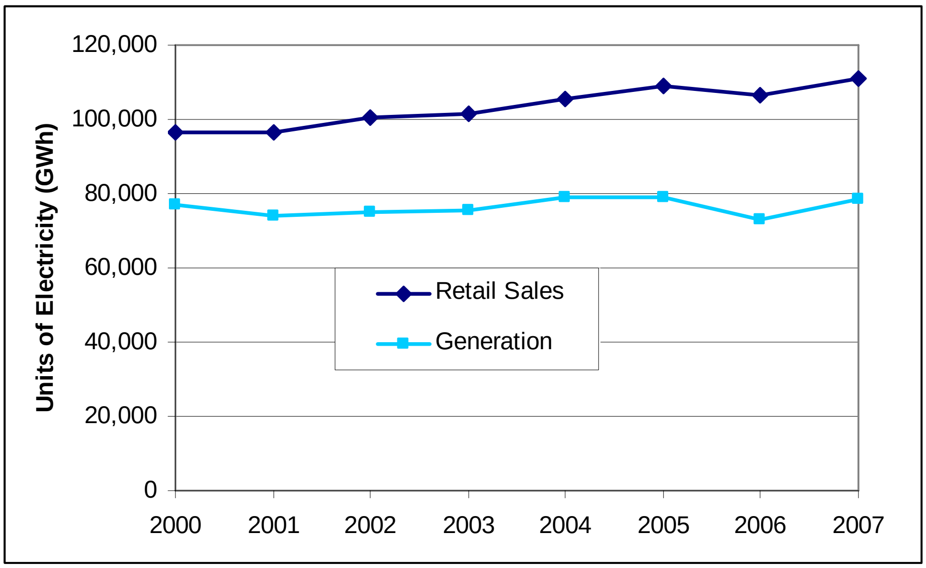
Electricity consumption in Virginia grew at an average annual rate of 2.0% over the 2000-2007 period of deregulation (EIA 2007b). As can be seen in Figure 1, electricity generation in the Commonwealth has remained below the level of demand, meaning that Virginia is a net importer of 30-40% of its electricity. All but a small portion of Virginia in the southwest is part of the PJM Interconnection, a regional transmission organization in the Mid-Atlantic that provides reliability planning, manages a wholesale power market, and manages long-term regional electric transmission planning. In general, the price of power is greater in the PJM market than that generated in-state, so a greater reliance on imported power is likely to increase the price of electricity.

Retail rate caps set in place as part of Virginia's regulatory process are set to expire at the end of 2008, which will open the door to higher electricity prices as rising fuel costs make it increasingly difficult for utilities to recover their operating costs. Dominion Virginia Power has already been granted an 18% rate increase for higher fuel costs by state regulators as of June 2008, and Appalachian Power Company (APCo) is awaiting approval for a rate-adjustment clause (see Figure 2 for a map of these electric service territories).

There are several major generation and transmission projects in the Commonwealth aimed at meeting growing demand. Construction of a coal-fired generation plant in southwestern Wise County began in June 2008 and is slated to be finished in four years. This facility, called the Virginia Hybrid Energy Center, will be capable of producing 585 MW of electricity when it comes online in 2012. In November 2007, the Nuclear Regulatory Commission (NRC) granted Dominion an Early Site Permit, though the company still requires additional licenses from both the NRC and the State Corporation Commission (SCC) to construct a third generating unit at its North Anna nuclear facility located in

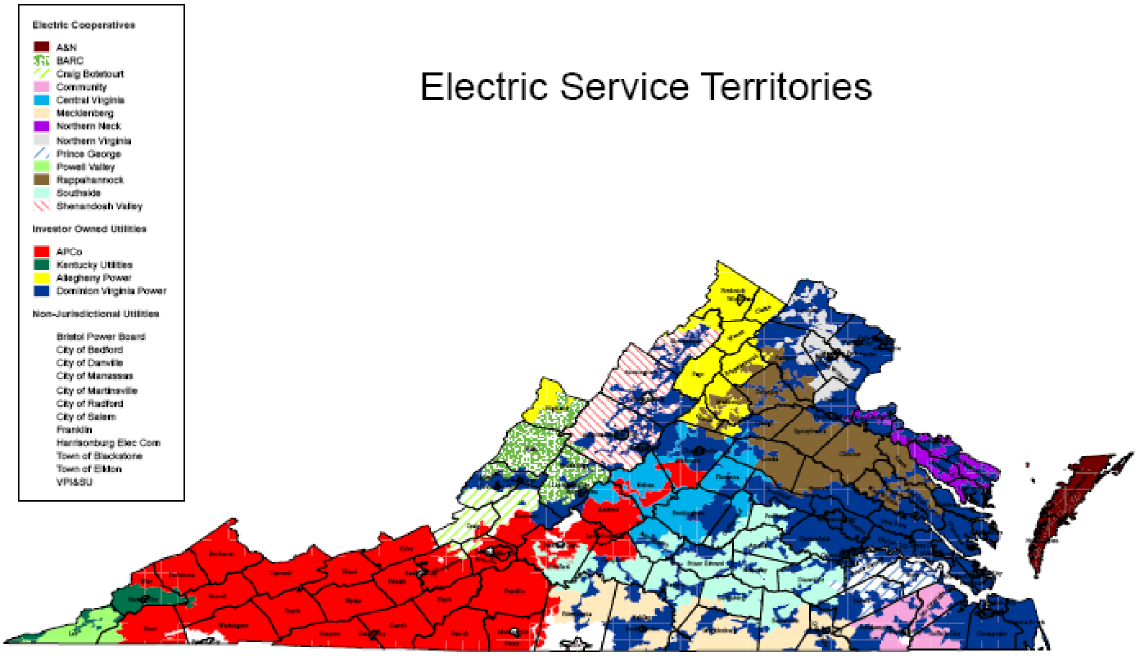
Louisa County. The new unit would add 1,520 MW of capacity to the facility, which is already capable of generating 1,786 MW, though commercial operation would not start until 2016 at the earliest. Also, Dominion owns a 600 MW Natural Gas Combined Cycle Generator plant in Buckingham County set to open in 2011 (Dominion 2007). There are two major transmission projects proposed that would affect the Commonwealth. Dominion and TrAILCo—a subsidiary of Allegheny Power—have proposed a 500 kV, 65-mile overhead transmission line stretching from Pennsylvania to Loudoun County with the purpose of serving future demand in Northern Virginia and other Mid-Atlantic states. Additionally, in 2007 PJM approved the construction of PATH-Allegheny's 250-mile, 765 kV transmission line extending from American Electric Power's (AEP) John Amos substation in St. Albans, West Virginia, to AEP's Bedington, northeast of Martinsburg, Maryland. Another 50 miles of twin-circuit 500 kV transmission lines will connect the Bedington substation to a new substation near Kemptown, southeast of Frederick, Maryland, which will be owned by Allegheny Power. This project is slated for completion in 2012.

Figure 1. Electricity Sales and Generation in Virginia, 2000-2007



Source: EIA 2007b, 2008a

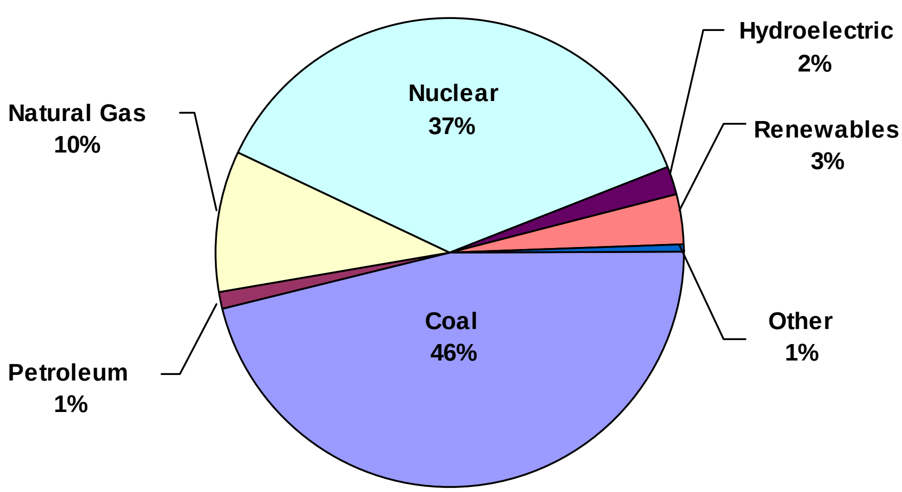
Figure 2. Electric Service Territories in Virginia



In 2006, Virginia generated 74,237 GWh of electricity (see Figure 1 and Figure 3). The majority of this in-state generated electricity came from coal-fired power plants (46%) and nuclear (37%). By comparison, the national average mix of electricity generation is 49% from coal and 19% from nuclear (EIA 2007b). In the same year, the state consumed 106,721 GWh of electricity, making the state a net importer of about 30% of its total electricity consumption (see Figure 1).

Figure 3. 2006 Virginia Electricity Generation by Fuel Type

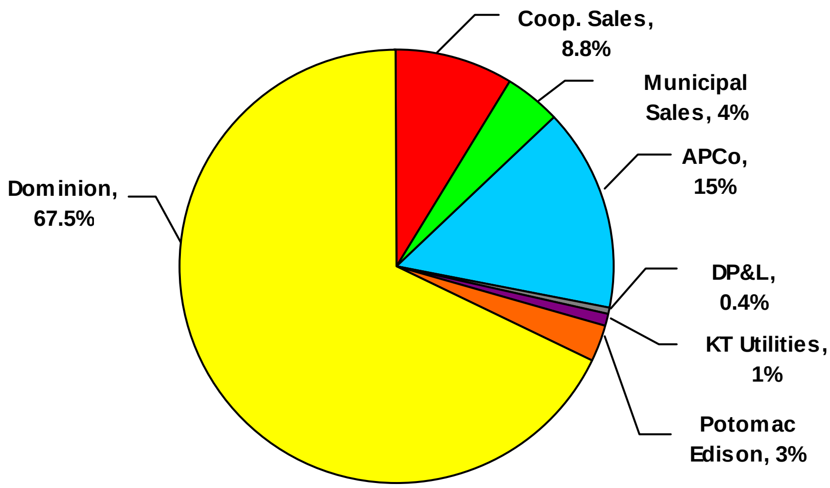
Total Generation: 74,237 GWh



Source: EIA 2008a

Electricity is delivered in Virginia to consumers by three types of providers: investor-owned utilities (IOUs), rural electric cooperatives (coops), and municipal electric suppliers. As can been seen in Figure 4, of the three types of providers, IOUs dominate the sales in the state (87%), with Dominion securing a 67.5% market share. Cooperatives and municipal utilities account for the remaining 13% of electricity sales.

Figure 4. Electricity Deliveries (GWh) by Supplier in 2006



Source: EIA 2007a

The failure of restructuring to introduce competition into Virginia's electricity market has perpetuated its vertical integration. The vast majority of electricity services (99.9%) are bundled; a negligible amount (<1.0%) is delivered to a third party for distribution.

Role of Energy Efficiency and Demand Response

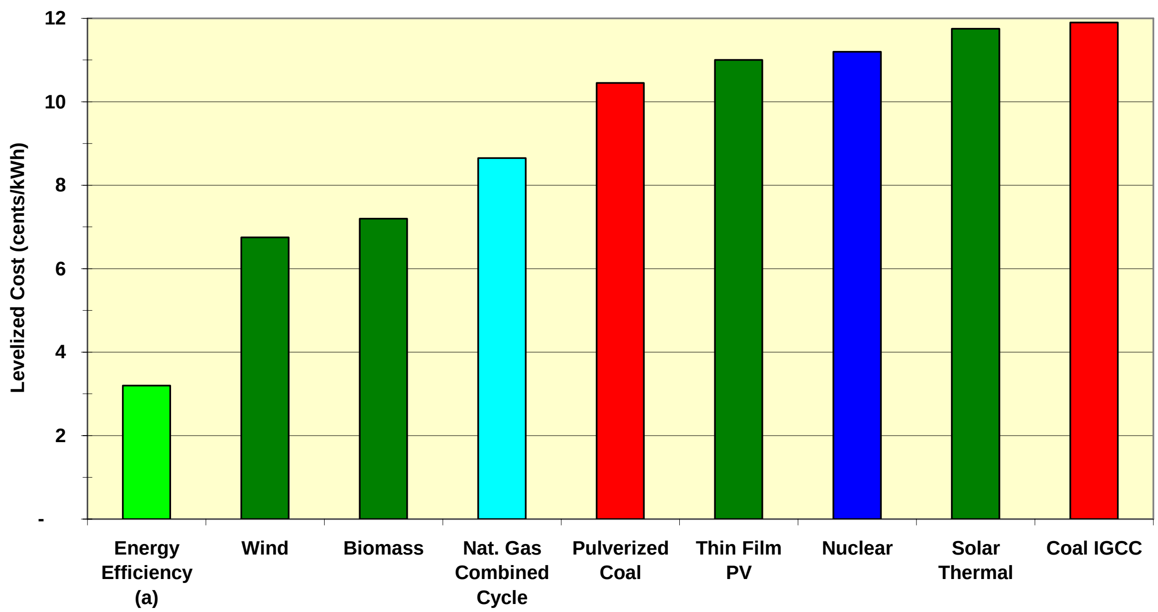
Virginia utilities are proposing several projects to meet the Commonwealth's increasing demand for electricity, as discussed above. The proposed investments in new generation and transmission have thus far not been complemented by notable efforts to expand the state's demand-side efficiency policies. In fact, Virginia ranked 38th out of the 50 states in ACEEE's 2006 state energy efficiency scorecard (Eldridge et al. 2007).

Recently, Virginia has taken steps towards a more pro-active focus on demand-side management. Recognizing that adding new capacity cannot completely satisfy the state's future electricity needs, Governor Timothy Kaine inserted an enactment clause into the March 2007 electricity restructuring legislation (S.B. 1416) stating that the Commonwealth shall have a goal of reducing electricity consumption by 10% (of 2006 consumption) by 2022 and directed the State Corporation Commission to conduct a proceeding to evaluate the stated goal and submit its findings and recommendations to the Governor and the General Assembly. The November 2007 SCC report states that the staff believes that the 10% electricity consumption reduction goal set forth by the General Assembly is attainable by 2022, though it suggests further exploration into the programs needed to achieve the goals and the cost-effectiveness of the programs (SCC 2007).

At the utility level, Dominion has recently introduced programs that aim to increase the prevalence and success of demand-side management within the state. In January 2008, the Virginia utility commission approved Dominion's implementation of nine pilot programs whose goal is to evaluate customer acceptance of various DSM programs (SCC 2008b). Through these programs, Dominion plans to address the potential for energy conservation, customer education, demand response, and load management to curtail electricity consumption within its service territory. In June 2008, Dominion introduced an aggressive energy conservation and demand reduction plan that includes the installation of "smart grid" technology, which Dominion will introduce to its Virginia customers pending Commission approval. Dominion estimates that these programs will shave electricity demand and consumption by 850 MW and 2,788 MWh by 2015, providing a significant step towards achieving Governor Kaine's goal of a 10% reduction (Dominion 2008).

In leading states, energy efficiency is meeting 1 to 2% of the state's electricity consumption each year (Nadel 2007; Hamilton 2008) at a cost of less than 3¢ per kWh (Kushler, York and Witte 2004), compared with a utility-avoided cost of about 6 to 8¢ per kWh in Virginia (see Figure 10).[2] States across the country, including California, Connecticut, Massachusetts, Minnesota, New York, and Vermont, are realizing the benefits of energy efficiency today, and have enacted policies and programs that effectively tap into their energy efficiency resources. Results from these states show that energy efficiency represents an immediate low cost, low risk strategy to help meet the state's future electricity needs (York, Kushler, and Witte 2008). In contrast, new supply options—either traditional or renewable—now cost significantly more, as is suggested in Figure 5.

Figure 5. Cost of New Energy Resources



Source: All estimates are midpoint of ranges from Lazard (2008), except (a) which is Nadel, Shipley and Elliott (2004).

Together, energy efficiency and demand response can delay the need for expensive new supply in the form of generation and transmission investments (Elliott et al. 2007; 2007b), thus keeping the future cost of electricity affordable for the state and freeing up energy dollars to be spent on other resources that expand the state's economy. In addition, a greater share of the dollars invested in energy efficiency go to local companies that create new jobs compared with conventional electricity resources, where much of the money flows out of state to equipment manufacturers and energy suppliers.

[2] The avoided cost analysis does not take into account a cost of carbon that would be imposed under a federal cap and trade program. If we assume a cost for carbon, which most experts predict, avoided costs to utilities could range from 8 to 10 cents per kWh.

Barriers to Energy Efficiency and Demand Response

While experience has demonstrated that energy efficiency and demand response resources are cost-effective and achievable, we have learned that they will not occur without specific policy interaction due to pre-existing market barriers. These barriers include:

- Awareness of energy efficiency opportunities—as one industrial manager characterized it, “you have to know what fruit looks like if you are going to harvest the low-hanging fruit” (Johnson 2008).
- Principal-agent barrier where the person making the efficiency investment does not benefit from the energy savings (e.g., a landlord installing efficient lighting when the tenant reaps the energy bill savings).
- Regulatory barriers (e.g., regulation may discourage utilities from investing in energy efficiency because they cannot fully recover their costs or make an attractive return on their DSM investments).
- Financial hurdles—the “Warren Buffet problem” that the private sector is inclined to do one large deal rather than lots of small deals, and energy efficiency is by its nature small and dispersed.
- Expanding demand response is a challenge since most consumers don't understand demand resources and its benefits, and that it requires both utility and customer investments in new infrastructure

Proactive legislative initiatives and policies are thus required to overcome these barriers and allow energy efficiency and demand response resources to be realized to their full potential.

Project Approach and Methodology

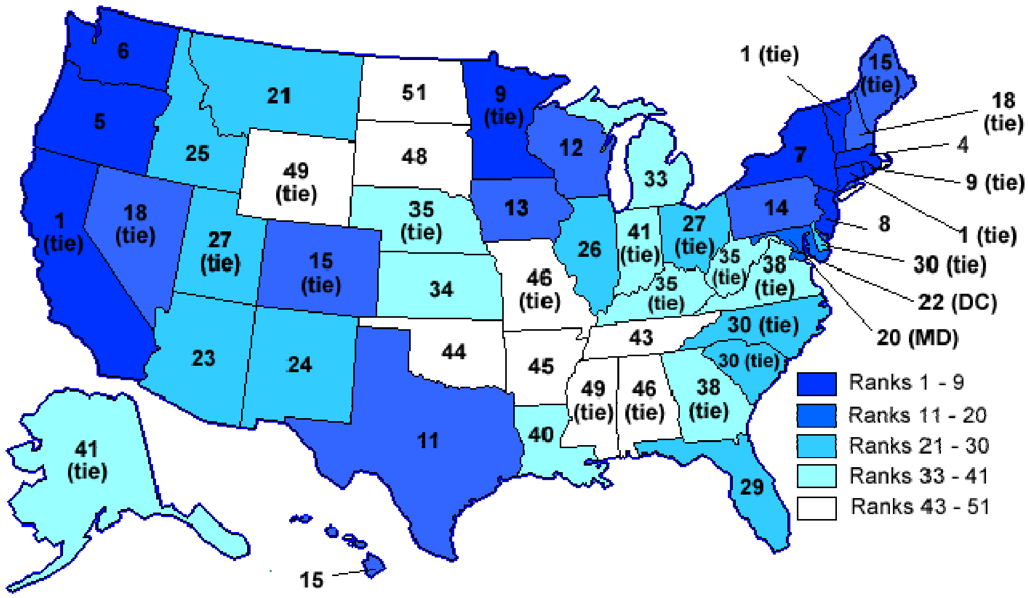
Overall Project Context: Why We Chose Virginia

For a number of years, ACEEE has published state clean energy scorecards, the first editions ranking utility-sector energy efficiency program spending and performance data, and more recently with a comprehensive ranking of state energy efficiency policies identifying exemplary programs and policies within several energy efficiency policy categories. The 2007 edition of the Scorecard was the first edition of this more comprehensive approach and the policy categories included:

1. Spending on Utility and Public Benefits Energy Efficiency Programs
2. Energy Efficiency Resource Standards (EERS)
3. Combined Heat and Power (CHP)
4. Building Energy Codes
5. Transportation Policies
6. Appliance and Equipment Efficiency Standards
7. Tax Incentives
8. State Lead by Example Programs

In the 2007 Scorecard, ACEEE noted that the top tier states, as shown in Figure 6, needed little or no help to continue to improve their energy efficiency programs and policies. Rather it was the middle tier of states, which are moving more slowly towards better energy efficiency programs but have started the process, that offered the best opportunity to encourage a quicker transition to greater energy efficiency. In ACEEE’s 2007 Scorecard, Virginia ranked # 38 as shown on the map and was, therefore, considered a middle tier state.

Figure 6. 2007 State Scorecard Results



Source: Eldridge et al. 2007

Recent interest by Virginia's Governor Tim Kaine and his administration has resulted in legislation directing various state agencies to review and consider new energy efficiency policies to reduce the state's growing energy demand. Some utilities, such as Dominion, are beginning to explore demand-side management through pilot programs. Due to this increased interest in energy efficiency and Virginia's growing energy demand (especially in the northern region of the state), ACEEE determined that the state might benefit from an analysis of how energy efficiency and complementary demand response initiatives could work in a cost-effective manner to fill the expected energy demand gap.

Stakeholder Engagement

ACEEE did not presume to know what energy policies would work best in Virginia. Talking to a broad range of stakeholders was an essential part in tailoring our proposal to fit the unique needs of the Commonwealth. Engaging the many interest groups in Virginia was a significant undertaking. We endeavored to meet in person with as many different sectors as possible in order to get the feedback required to better understand Virginia's specific energy structure and needs. We met with many of the environmental groups; the Governor's staff; the Virginia Manufacturing Association membership; utility companies including Dominion, Appalachian Power, and the Virginia Association of Electric Cooperatives; the State Commonwealth Commission; and various other interested organizations in the state. We also called various legislators' offices and representatives of the low income communities for their input.

We shared the draft report of this study with representatives of all of these stakeholders for their review, and their comments have been incorporated in this report as appropriate. A final follow up with stakeholders included presentations of the reports results at the Virginia Manufacturers Forum in Richmond on September 17th, meetings with environmental organizations on the 18th, and finally a presentation at the Governor's Commonwealth of Virginia Energy and Sustainability Conference held in Richmond from Sept. 17th through 19th.

Analysis

The remainder of the report presents a description of the analysis methodology and results in the following order:

- ***Reference Case:*** In addition to the extensive stakeholder phase of this study, the first step in conducting an energy efficiency and demand response potential study for Virginia was to collect data and to characterize the state's current and expected patterns of electricity consumption over the study time period (2008-2025). In this section, we describe the assumed reference forecasts for electricity, peak demand, electricity supply prices, and avoided costs based on available data that ACEEE has been able to collect and projections developed by Synapse Energy and Economics, as presented in Appendix A.1.

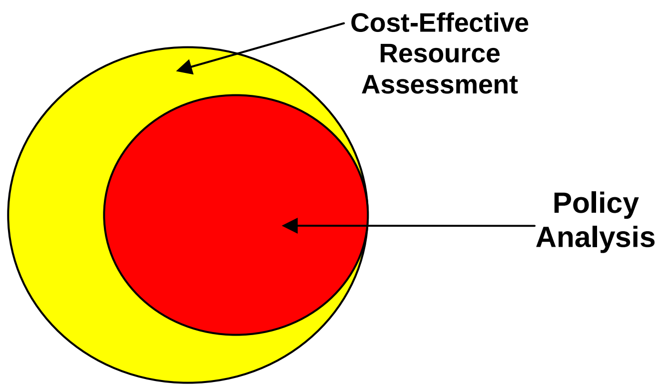
- ***Energy Efficiency Resource Assessment:*** Following the Reference Case section is the energy efficiency resource assessment, which examines the overall potential in the state for increased cost-effective electricity efficiency using technologies and practices of which we are currently aware (see Figure 7). Cost-effectiveness is evaluated from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of electricity). We review specific, efficient technology measures that are technically feasible for each sector; analyze costs, savings, and current market share/penetration; and estimate total potential from implementation of the resource mix. The technology assessment is reported by sector (i.e., residential, commercial, and industrial) and includes an analysis of potential for expanded CHP, which was prepared by ICF International. An important caveat for the reader to note is that we review only existing technologies and practices that have reasonable market share but do not consider emerging technologies and practices with very low market share or that have yet to emerge. Therefore, potential for increased efficiency is likely higher throughout the study time period given the likelihood that some emerging technologies will be commercialized and become cost-effective. See Appendix C for a detailed methodology of the resource potential analysis by sector.

- ***Energy Efficiency Policy Analysis:*** For this analysis, we developed suites of energy efficiency policy recommendations based on successful models implemented in other states and in consultation with stakeholders in Virginia. This analysis assumed a reasonable program and policy penetration rate, and therefore is less than the overall resource potential (see Figure 7). We drew upon our resource assessment and evaluations of these policies in other states to estimate the electricity savings and the investments required to realize the savings. The cost-effectiveness of the recommended programs and policies are evaluated using the TRC test and the Participant test. We also estimate the reductions in peak demand that would occur as a result of these energy efficiency policies and programs. See Appendix B for detailed results.

- ***Demand Response (DR) Analysis:*** The Demand Response Analysis, prepared by Summit Blue Consulting, assesses current demand response activities in Virginia, uses benchmark information to assess the potential for expanded activities in Virginia, and offers policy recommendations that could foster DR contributing appropriately to the resource mix in Virginia that could be used to meet electricity needs. Potential load reductions are estimated for a set of DR programs that represent the technologies and customer types that span a range of DR efforts, and are in addition to the demand reductions resulting from expanded energy efficiency investments. The demand response policy analysis is presented in Appendix D.

- ***Macroeconomic Impacts:*** Based on the electricity savings, program costs, and investment results from the policy analysis, we ran ACEEE's macroeconomic model, DEEPER, to estimate the policy impacts on jobs, wages, and gross state product (GSP). For a more detailed discussion of DEEPER and the macroeconomic analysis, see Appendix F.

Figure 7. Levels of Energy Efficiency Potential Analysis



REFERENCE CASE

The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a "business as usual" scenario. In this section we report the reference case assumptions for the analysis time period, 2008-2025. See Appendix A for more detailed information on the reference case assumptions.

Electricity (GWh) and Peak Demand (MW)

We base our forecast of electricity consumption growth on PJM's 2008 annual load forecast through 2022, using only its service territories in Virginia to derive weighted-average growth rates for Virginia. We then apply this overall forecast to actual 2007-year electric sales data by sector for Virginia (EIA 2007b) and adjust sector-specific growth rates using *Annual Energy Outlook* sector growth rate ratios for the South Atlantic region (EIA 2007c). Using this methodology, and extending the forecast through 2025 to cover the study period of this analysis, total electricity consumption in the state is projected to grow in the reference case at an average annual rate of 1.4% between 2008 (the analysis base year) and 2025, and 1.2%, 2.0%, and 0.2% in the residential, commercial, and industrial sectors, respectively. Actual electricity consumption in the residential, commercial, and industrial sectors in 2007 was 110,924 GWh (EIA 2007b), and in the reference case grows to 126,833 GWh by 2015 and 144,195 GWh by 2025 (see Figure 8 and Appendix A).

We derive a peak demand (MW) forecast for Virginia from the electricity forecast described above and assume a 55% load factor, based on PJM load data for Dominion in 2007. Using this methodology, we estimate a 2008 peak demand of about 26,000 MW, rising to nearly 33,000 MW in 2025 and an average annual growth rate of 1.4%.

Utility Avoided Costs

At ACEEE's request, Synapse Energy Economics developed simplified, high-level projections of utility production and avoided marginal costs. We then used these results in ACEEE's analysis to estimate the cost-effectiveness of energy efficiency measures and assess the macroeconomic impacts. The avoided cost estimates are based upon a number of simplifying and conservative assumptions that the stakeholder group considered reasonable for the purpose of this high-level policy study. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. In a further conservatism, we did not include a cost of compliance with anticipated greenhouse gas emissions regulations. As a result, the production and avoided cost estimates used should be viewed as unrealistically low. A detailed discussion of the assumptions and avoided cost estimates can be found in Appendix A.2.

Figure 8. Electricity Forecast by Sector in the Reference Case

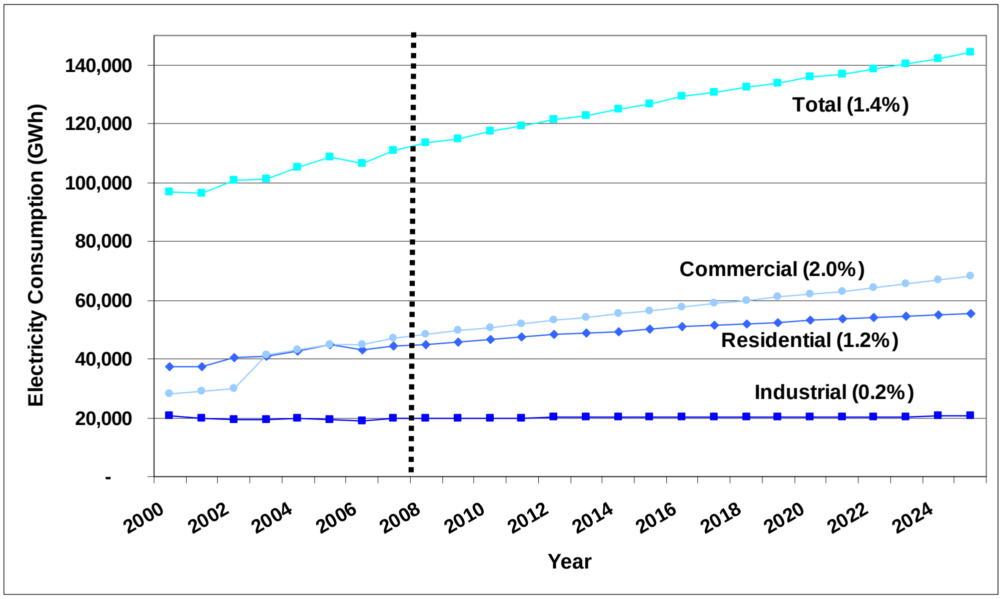
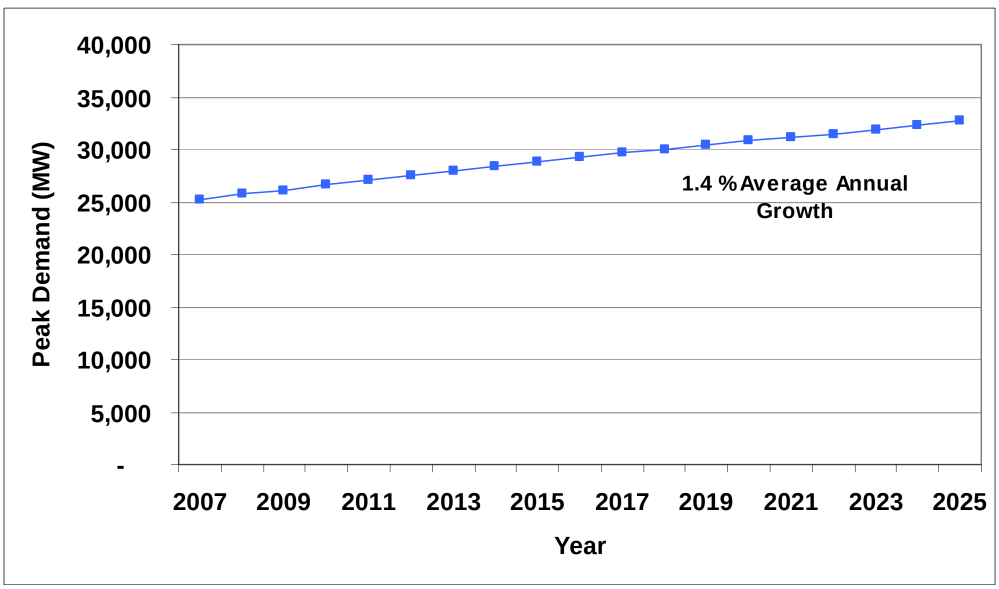
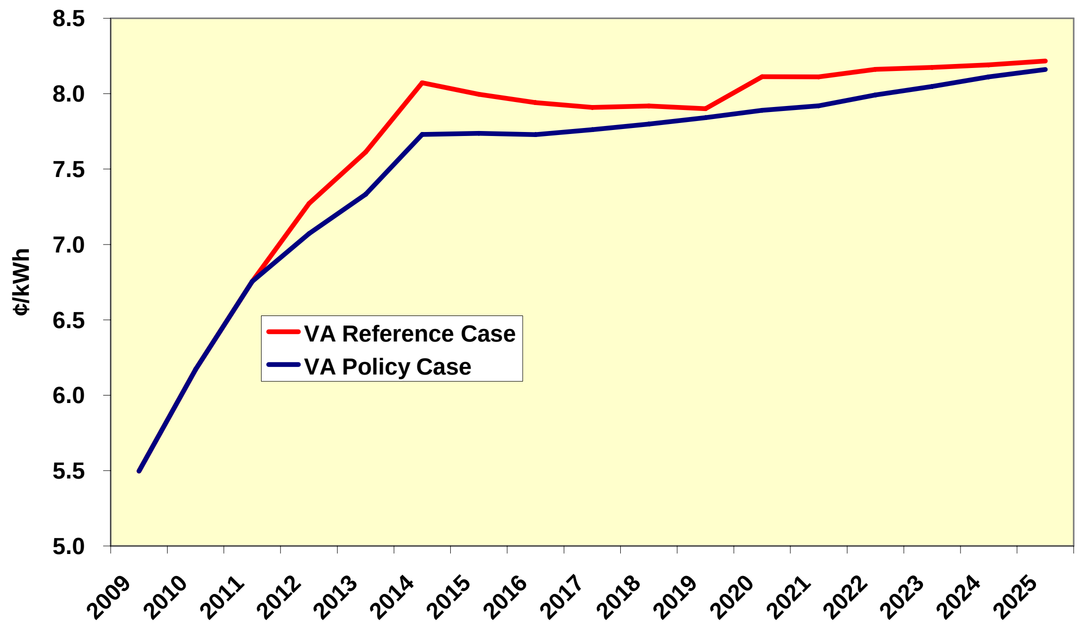


Figure 9. Virginia Peak Demand Forecast



Because the level of energy efficiency and demand response measures assessed in this study significantly change the requirements for future resources, we developed two sets of production and avoided costs projections. The first case reflects the market conditions that would be anticipated in the reference case. The second case reflects the medium energy efficiency policy case discussed below. As would be anticipated, the policy case produced modestly lower avoided resource costs than the reference case, as can be seen in Figure 10. As a further conservatism in our analysis, we used this second, lower set of costs in valuing the savings that resulted from the analyzed policies and programs.

Figure 10. Estimates of Average Annual Avoided Resource Costs



It is important to note that because these projections represent a highly stylized representation of costs, we suggest that a more detailed assessment of costs be undertaken as part of the Commonwealth's energy planning process that can reflect the locational and temporal variation across the state and throughout the year.

Retail Price Forecast

ACEEE also developed a possible scenario for retail electricity prices in the reference case. Readers should note the important caveat that ACEEE does not aim to predict what electricity prices in Virginia will be in either the short or long term. Rather, our goal is to suggest a possible scenario, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Virginia.

Table 1 shows 2007 electricity prices in Virginia (EIA 2008a) and our estimates of retail rates by customer class over the study time period. This price scenario is based on three key factors. First, we use the average generation cost of electricity in Virginia over the time period from the analysis done by Synapse Energy Economics (discussed above). Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the Southeastern Electric Reliability Council (SERC) (EIA 2007c). Finally, we estimate expected near-term increases due to fuel adjustments by investor-owned utilities and expectations of rate caps expiring in December 2008. More details on the methodology and assumptions used to develop these projections are presented in Appendix A.2.

Table 1. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2006$)

	2007*	2010	2015	2020	2025	Average
Residential	8.5	10.1	10.0	10.1	10.5	10.0
Commercial	6.3	9.1	8.9	9.1	9.4	8.9
Industrial	4.9	6.8	6.8	6.9	7.2	6.8
Average	6.9	8.8	8.7	8.9	9.2	8.7

Note: These figures are in real, 2006-year dollars and therefore do not take into account inflation.
* Actual rates (EIA 2008a), converted to 2006$

ENERGY EFFICIENCY COST-EFFECTIVE RESOURCE ASSESSMENT

This section presents results from our assessment of cost-effective energy efficiency resources in residential and commercial buildings, the industrial sector, and combined heat and power (CHP). Cost-effectiveness of more efficient technologies is determined from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of electricity for a given customer class). More detailed information on methodology and results is given in Appendix C. Table 2 presents a summary of energy efficiency potential by sector in 2025. This assessment includes only existing technologies and practices. We anticipate that new and emerging technologies and market learning will significantly increase the cost-effective efficiency resource potential by 2025.

Table 2. Summary of Cost-Effective Energy Efficiency Potential in Virginia by Sector (2025)

Sector	Efficiency Potential (GWh)	As % of Electricity Consumption in 2025
Residential	14,328	26%
Commercial	19,191	28%
Industrial	5,152	25%
Combined Heat & Power	5,700	6%*
Total	44,371	31%

** Note: As percentage of commercial and industrial sectors combined.*

Residential Buildings

To examine the cost-effective potential for energy efficiency resources in Virginia's residential sector, we considered a scenario with widespread adoption of cost-effective energy efficiency measures during the 18-year period from 2008 to 2025. We evaluated 34 efficiency measures that might be adopted in existing and new residential homes based on their relative cost-effectiveness. An upgrade to a new measure is considered cost-effective if its levelized cost[3] of conserved energy (CCE) is less than 10 cents per kWh saved, which is the average retail residential electricity price in Virginia over the study time period (see Table 1). However, the substantial majority (85%) of the total efficiency potential has a levelized cost of 8 cents per kWh saved or less and 41% of the measures have a cost of 3 cents per kWh or less. For the sum of all measures, we estimate a levelized cost of less than 4 cents per kWh saved (see Table 3).[4] See Appendix C.1 for a detailed methodology and specific efficiency opportunities and cost-effectiveness for residential buildings (Table C.1). Also shown in Appendix C.1 is a characterization of a typical household in Virginia and the resulting energy bill savings from implementation of the efficiency measures described below.

[3] Levelized cost is a level of investment necessary each year to recover the total investment over the life of the measure.
[4] Assuming a 5% real discount rate.

Table 3. Residential Energy Efficiency Potential and Costs by End-Use

End-Use	Savings (GWh)	Savings (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC	5,940	11%	41%	$ 0.043
Water Heating	1,695	3%	12%	$ 0.074
Lighting	2,939	5%	21%	$ (0.003)
Refrigeration	447	1%	3%	$ 0.060
Appliances	76	0%	0.5%	$ 0.078
Furnace Fans	1,005	2%	7%	$ 0.035
Plug Loads	900	2%	6%	$ 0.021
Electricity Use Feedback	376	1%	3%	$ 0.022
Existing Homes	**13,378**	**24%**	**93%**	**$ 0.034**
New Homes	**949**	**2%**	**7%**	**$ 0.054**
All Electricity	**14,328**	**26%**	**100%**	**$ 0.036**

We estimate an economic potential for efficiency resources of 14,328 GWh in the residential sector over the 18-year period of 2008–2025, a potential savings of 26% of the reference case electricity consumption in 2025 (Table 3). Existing homes can reduce electricity consumption by 24% through the adoption of a variety of efficiency measures (see Appendix C, Table C.1). While newly constructed homes built today can readily achieve 15% energy savings (ENERGY STAR® new homes meet this level of efficiency), we also estimate that new homes can reach 30% to 50% energy savings cost-effectively. We estimate that new residential homes can yield electricity savings of about 949 GWh by 2025, or 7% of total potential savings in the residential sector.

In the residential sector, significant savings from electricity efficiency resources are realized through improved housing shell performance (e.g., insulation measures, duct sealing and repair, reduced air infiltration, and ENERGY STAR windows) and more efficient heating, ventilation, and air conditioning (HVAC) equipment and systems.[5] HVAC equipment, air distribution, efficient furnace fans, and load reduction measures account for 48% of potential savings.

Substantial savings are also attributed to improvements in lighting systems and water heating (including both more efficient water heaters as well as water-consuming appliances). As a fraction of total savings potential in the residential sector, lighting constitutes 21% and water heating 12% of potential savings (see Figure 11). There is considerable potential for efficiency resources in both existing and new homes in Virginia to be realized simply by replacing household incandescent light bulbs with more efficient compact fluorescent light bulbs (CFLs). Measures to reduce hot water loads (such as high-efficiency clothes washers, low-flow showerheads, and water heater jackets and pipe insulation) can yield additional savings for households with electric water heaters. The use of more efficient water heaters, particularly advanced technologies such as heat-pump water heaters, can further reduce electricity used for water heating.

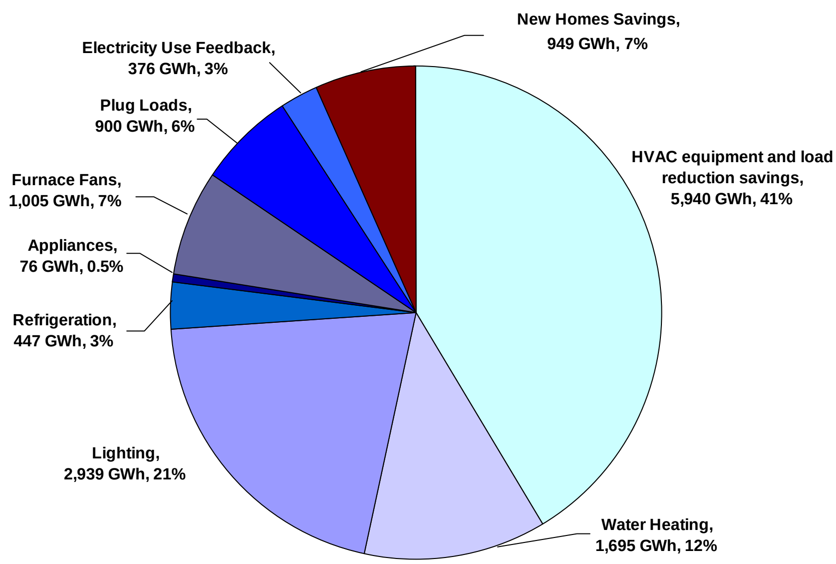
More efficient household appliances can also yield significant savings. Our analysis shows the savings potential of replacing existing refrigerators, clothes washers, and dishwashers with units that are better than minimum ENERGY STAR models (Consortium for Energy Efficiency "Tier 2" in most cases), or by having builders install these more efficient models in new homes. Another 6% of the total savings potential can be attributed to reducing the power consumption of electronic devices that use considerable amounts of energy in standby mode. We include a measure for reducing television power consumption in active mode, which is based on ENERGY STAR's Draft 2 Specification revision. These measures are among the most cost-effective in the residential sector. The balance of potential savings comes from installing a real-time energy use feedback mechanism. Although

[5] Savings from air-conditioners assume a baseline of 13 SEER equipment, which is the recently updated federal standard.

involving a behavioral component, in-home monitors, which allow residents to track how much electricity their house is using, have been documented to result in significant and persistent savings.

Figure 11. Residential Energy Efficiency Potential in 2025 by End-Use in Virginia

Total: 14,328 GWh
26% of Projected Electricity Consumption in 2025



Commercial Buildings

We examined thirty-six energy efficiency measures in the commercial buildings sector to determine the potential for electricity resources from energy efficiency. Thirty-three of these measures are applicable to existing buildings, and each of these measures was categorized by end-use: HVAC; water heating; refrigeration; lighting; office equipment; and appliances/other. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy (CCE) is less than 8.9 cents per kWh saved, which is the average retail commercial electricity price in Virginia over the study time period (see Table 4). In addition we examined savings for new buildings that are 15%, 30%, and 50% better than current energy code. To calculate the potential from each of these measures, we first gathered information on baseline electricity consumption in Virginia commercial buildings, and then characterized new measures by collecting data on savings, costs, lifetime of the measure, and the percent of buildings for which the measure is applicable. See Appendix C.2 for a detailed description of the methodology. Table 4 and Figure 12 show results for energy efficiency potential in commercial buildings by 2025. Results by specific measure are shown in Appendix C.2. We estimate that by 2025, Virginia can reduce its commercial building electricity consumption by 28% at a levelized cost of about $0.018 per kWh saved.[6]

The largest share (44%) of the resource potential is in lighting, which includes measures such as replacing incandescent lamps, fluorescent lighting improvements, and lighting control measures such as daylight dimming systems and occupancy sensors. The second largest share comes from HVAC measures: reduced HVAC loads; improved heating and cooling systems; and HVAC equipment control measures (21% of resource potential). Measures to reduce HVAC loads include low-e replacement windows, duct testing and sealing, and roof insulation. Equipment upgrades include high-efficiency unitary air conditioners and heat pumps for smaller buildings and high-efficiency

[6] Assuming a 5% real discount rate.

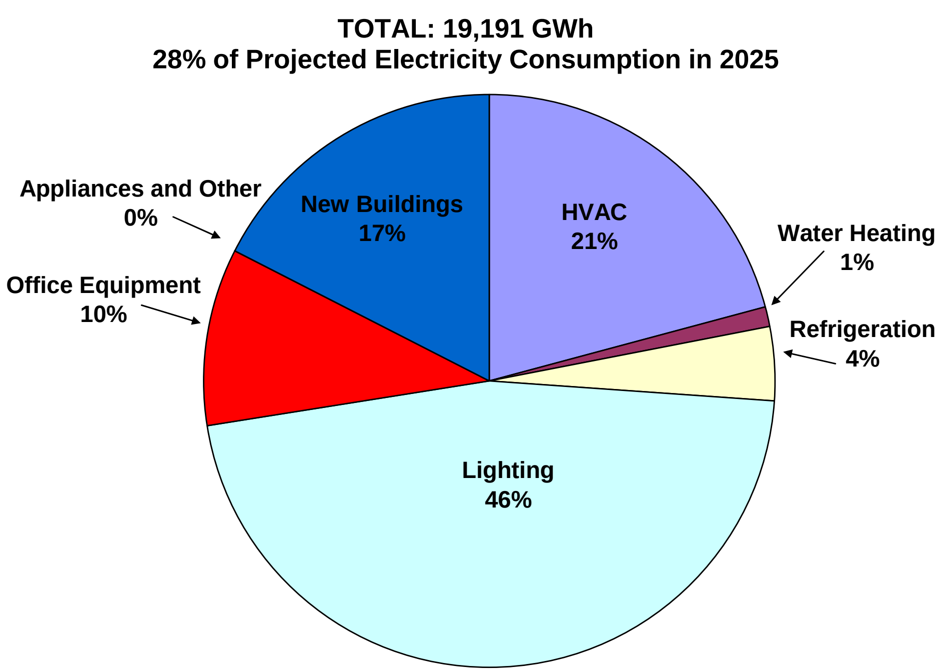
chillers and systems for larger buildings. Measures to further increase HVAC efficiency through controls include energy management systems and whole-building retrocommissioning.

Table 4. Commercial Energy Efficiency Potential and Costs by End-Use

End-Use	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Resource Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
Existing Buildings				
HVAC	3,993	5.9%	21%	$ 0.028
Water Heating	228	0.3%	1%	$ 0.033
Refrigeration	796	1.2%	4%	$ 0.017
Lighting	8,878	13%	46%	$ 0.011
Office Equipment	1,935	2.8%	10%	$ 0.003
Appliances and Other	13	0.0%	0%	$ 0.101
Subtotal	15,843	23%	83%	$ 0.015
New Buildings	3,348	4.9%	17%	$ 0.031
Total	**19,191**	**28%**	**100%**	**$ 0.018**

New, high-performance commercial buildings built today can cost-effectively reduce electricity consumption by 15 to 50% compared to building energy codes. As shown in Table 4, we estimate that efficient new buildings can reduce total electricity consumption by about 4.9% in 2025, which represents 17% of the total potential.

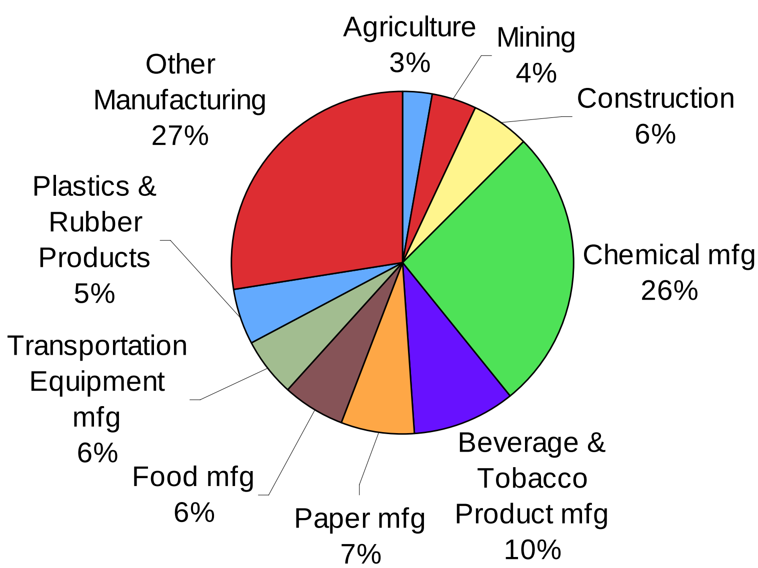
Figure 12. Commercial Energy Efficiency Potential in 2025 by End-Use in Virginia



Industry

The industrial sector is the most diverse economic sector, encompassing agriculture, mining, construction and manufacturing. Because electricity use and efficiency opportunities vary by individual industry—if not individual facility, it is important to develop a disaggregated forecast of industrial electricity consumption. Unfortunately this energy use data is not available at the state level, so ACEEE has developed a method to use state-level economic data to estimate disaggregated electric use. This study drew upon national industry data to develop a disaggregated forecast of economic activity for the sector. We then applied electricity intensities derived from industry group electricity consumption data reported and the value of shipments data to characterize each sub-sector's share of the industrial sector electricity consumption (see Figure 13). Despite changes in economic activity and changes in energy intensity, there were few significant intra-sectoral shifts in energy consumption. As the figure shows, the largest industrial electricity consumers are the chemical, paper, and beverage/tobacco industries. Agriculture, mining, and construction are relatively minor electricity consumers compared to many other states, so they are not a major focus of this study.

Figure 13. Estimated Electricity Consumption for the Largest Consuming Industries in Virginia in 2008



We examined 18 electricity saving measures, 10 of which were cost effective considering Virginia's average industrial electric rate of $0.068 /kWh. These measures were applied to an industry specific end-use electricity breakdown. Table 5 shows results for industrial energy efficiency potential by 2025.

This analysis found economic savings from these cross-cutting measures of 3,726 million kWh or 18% of industrial electricity use in 2025 at a levelized cost of about $0.02 per kWh saved. This analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available time, funding, and data did not allow this level of analysis. However, based on experience from site assessments by the U.S. Department of Energy and other entities, we would anticipate an additional economic savings of 5–10%, primarily at large energy-intensive manufacturing facilities. So the overall economic industrial efficiency resource opportunity is on the order of 23–28%. Therefore, the total economic potential for the industrial sector in 2025 would be about 5,152 GWh.

Table 5. Industrial Energy Efficiency Potential and Costs by Measure

Measures	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Resource Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
Sensors & Controls	75	0.4%	2%	$0.01
Energy Information Systems	199	1.0%	5%	$0.06
Duct/Pipe insulation	663	3.2%	18%	$0.05
Electric Supply	618	3.0%	17%	$0.01
Lighting	310	1.5%	8%	$0.02
Total Motors	866	4.2%	23%	$0.03
Total Compressed Air	311	1.5%	8%	$0.00
Pumps	468	2.3%	13%	$0.01
Fans	133	0.6%	4%	$0.02
Refrigeration	84	0.4%	2%	$0.00
Total	**3,726**	**18%**	**100%**	**$0.02**

Combined Heat and Power

CHP provides substantial increases in overall fuel efficiencies by generating both thermal and electric power from a single fuel source. This co-generation approach bypasses most of the thermal losses inherent in traditional thermal electricity generation, where half to two-thirds of fuel input is rejected as waste heat. By combining heat and power in a single process, CHP systems can produce efficiencies of 70% or greater (Elliott and Spurr 1998).

For this report, Energy and Environmental Analysis (EEA), a division of ICF International, undertook an assessment of the cost-effective potential for CHP in Virginia. EEA identified about 322 MW from 9 operating CHP plants currently operating in the state.[7] The addition potential was estimated by assessing the electricity end-uses at existing industrial, commercial, and institutional sites across the Commonwealth and also considering sites that will likely be built in the future. These facilities would replace a thermal system (usually a boiler) with a CHP system that also produces power and that is primarily intended to replace purchased power that would otherwise be required at the site. Detailed information from this analysis is provided in Appendix E.

An additional application of CHP considered by this analysis is in the production of power and cooling though the use of thermally activated technologies such as absorption refrigeration. This application has the benefit of producing electricity to satisfy onsite power requirements and displacing electrically generated cooling, which reduces demand for electricity from the grid, particularly at periods of peak demand (see Elliott and Spurr 1998).

Three levels of potential for CHP were assessed (see Appendix E for detailed results):

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic potential*, as shown in Table 6, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail in Appendix E.
- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

[7] This estimate excludes "qualifying facilities" under *Public Utility Regulatory Policy Act 1978*, Sec. 210. For a expanded discussion, see Elliott and Spurr (1998).

This potential is described in the energy efficiency policy scenarios, which are shown in the next section of the report.

Table 6. Economic Potential for CHP in Virginia by System Size

	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
Economic Potential	202	58	313	78	733	1,384

Examples of Energy Efficiency Programs

While an EERS target is independent of specific programs, there are many program designs that have proven successful over the past three decades. We present several of these program types below, along with specific examples of successful implementations that are drawn from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008).

- ***Commercial/Industrial Lighting Programs***: Provide recommendations and incentives to businesses to increase lighting efficiency. Aiming to expedite the adoption of new technologies and decrease end-user's energy costs, the programs focus on marketing the most advanced lighting products and encourage greater efficiency in system design and layout. Xcel Energy's *Lighting Efficiency* program reached 4,346 participants, saving a total of 273 GWh during the years 2002-2006.

- ***Commercial/Industrial Motor and HVAC Replacement Programs*:** Encourage the marketing and adoption of higher efficiency motors and HVAC equipment by offering rebates to distributors and end-users of qualifying equipment. Through monetary incentives and energy efficiency education, program advocates are shifting market tendencies away from a focus on initial equipment cost and toward an environment where lifecycle cost is increasingly considered by consumers. During 2006, Pacific Gas & Electric's *Motor and HVAC Distributor Program* saved a total of 16.55 GWh of electricity by offering $3.9 million in rebates.
- ***Commercial/Industrial New Construction Programs:*** Focus on training, educating, and providing financial incentives for architects, engineers, and building consultants to implement energy saving measures and technologies. By offering both prescribed and customizable incentive packages, these programs are able to influence a wide range of projects, which have in turn had the effect of raising the standards for energy efficiency in normal building practices. With its four distinct, yet combinable project "tracks," Energy Trust of Oregon, Inc.'s *Business Energy Solutions: New Buildings* program offers qualifying projects incentives of up to $465,000 each, which saved approximately 46.8 GWh of electricity and 1.2 million therms of natural gas through the end of 2007.
- ***Commercial/Industrial Retrofit Programs:*** With programs ranging from energy efficiency audits to financial assistance to even providing detailed engineering installation plans, Commercial/Industrial Retrofit Programs are designed to help implement cost-effective energy efficiency measures during new construction, expansion, renovation, and retrofit projects in commercial buildings. Programs focus on long-term energy management, peak load reduction, load management, technical analysis, and implementation assistance in order to give building owners and operators a better understanding of the energy related costs of, and potential savings for, their commercial buildings. Rocky Mountain Power and Pacific Power created approximately 100 GWh of gross electricity savings in Washington and Utah with their *Energy FinAnswer and FinAnswer Express* programs.

- ***Residential Lighting and Appliances:*** Headed by utility companies and energy nonprofits alike, Residential Lighting and Appliances Programs advocate the adoption of ENERGY STAR light bulbs, light fixtures, and home appliances through the use of rebates, marketing campaigns, advertising, community outreach, and retailer education. Lighting programs have focused on establishing and maintaining a customer base for compact fluorescent bulbs, in addition to fostering relationships between manufacturers and retailers in order to lower costs to the consumer. Appliance programs have sought to educate consumers on the long-term benefits of replacing aging, inefficient refrigerators, freezers, air conditioning units, and other large appliances with ENERGY STAR models, while providing an incentive to upgrade older models through rebates offered both for recycling old units and purchasing new ones. By selling 1.3 million CFLs during 2006 through its *Energy Star Residential Lighting Program*, Arizona Public Service anticipates saving a total of 360 GWh of electricity during the lifetime of the light bulbs. Additionally, the *California Statewide Appliance Recycling Program* recycled 46,829 aging appliance units in 2007, a measure that saved 33.3 GWh of electricity in 2006.

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- ***Residential Mechanical Systems Programs:*** Provide rebates and other financial incentives to contractors trained to properly install and service high-efficiency air conditioning, heat pumps, and geothermal heat-pump technologies. In addition to encouraging the purchase of energy-efficient appliances, these programs help to verify that existing equipment is appropriately installed and tuned in accordance with manufacturers' specifications, in order to optimize energy savings. Long Island Power Authority's *Cool Homes* Program has helped to introduce approximately 40,000 high-efficiency central cooling systems into the market, creating 29 GWh of annual electricity savings in 2006.
- ***Residential New Homes Programs:*** Provide incentives to builders who construct energy-efficient homes that achieve long-term, cost-effective energy savings. By addressing efficiency during the construction of homes and apartments, builders are able to maximize the financial and environmental benefits of efficient insulation, windows, air ducts, and appliances. Furthermore, ENERGY STAR certification provides developers with additional marketing strategies to attract buyers and renters. Some Residential New Homes programs also offer assistance to builders in developing efficiency objectives, and to potential buyers in locating efficient homes. With 100 participating residential builders and over 2,300 homes built to date, Rocky Mountain Power's *Energy Star New Homes Program* saved 3.4 GWh of electricity during 2006.
- ***Residential Retrofit Programs:*** With an emphasis on large scale systematic retrofits, Residential Retrofit Programs are designed to reduce electric and natural gas consumption and peak-time demand of residential buildings. Financial incentives, low-interest financing, and training are offered to residents and customers interested in assessing and improving their energy efficiency. From weatherization and duct sealing to installation of new technologies, proponents of Residential Retrofit Programs direct their efforts both to buildings with the highest energy usage and constituents with the greatest financial need. Since its inception in 1993, Vermont Gas Systems, Inc.'s *HomeBase Retrofit Program* has installed over 1,600 kWh in energy saving measures, contributing to over 77,000 Mcf of natural gas savings.

- ***Low-Income Programs:*** Seek to educate and assist qualifying participants in acquiring appropriate home weatherization, energy-efficient lighting and appliances, and other efficiency improvements. By helping limited income households increase their energy efficiency and reduce energy consumption, these programs in turn minimize long-term energy costs to customers. Through its *Appliance Management Program and Low-Income Services*, National Grid has reached over 40,000 customers, creating 42 GWh of annual energy savings.

ENERGY EFFICIENCY POLICY ANALYSIS

In this section, we outline three policy scenarios: a low, medium, and high case for energy efficiency policy and program implementation. Each scenario is comprised of a suite of energy efficiency policies and programs that are suggested for implementation or extension in Virginia and would begin to tap into the available energy efficiency resource potential described above. The more aggressive the scenario, the more the state takes advantage of its available, cost-effective resource potential. The three scenarios are shown in the matrix below (see Table 7) and the results of the scenarios are discussed next, including the estimated electricity and peak demand savings, and finally costs and electricity bill savings. Then we provide more detailed descriptions of the policies and assumptions under each policy scenario. For the recommended programs or supporting policies that aren't easily quantified in terms of energy impacts, we summarize what the efforts could look like but do not estimate energy impacts.

Table 7. Matrix of Energy Efficiency Policies and Programs in Low, Medium, and High Level Case Scenarios

	Scenario One: Low Case	**Scenario Two: Medium Case**	**Scenario Three: High Case**
Energy Efficiency Resource Standard (EERS) *	10% (of 2006 electricity use) by 2022	15% (of 2006 electricity use) by 2022; extend 1% per year target to 2025 (relative to prior-year sales)	19% (of 2006 electricity use) by 2022; extend 1.5% per year to 2025 (relative to prior-year sales)
Demand Response **	Low participation (10-20%) and curtailment (15-20%) rates and low (30%) backup generation potential	Medium participation (20-30%) and curtailment (20-30%) rates and medium (40%) backup generation potential	High participation (30-40%) and curtailment (25-40%) rates and high (50%) backup generation potential
Combined Heat & Power Supporting Policies	No supporting policies	Some incentives and removal of disincentives toward CHP	Expanded incentives and removal of disincentives toward CHP
Manufacturing Initiative	Limited activities	Expanded state manufacturing initiative	More aggressive state manufacturing initiative combined with economic development incentives
State Facilities	Current ESCO initiative	Expanded ESCO initiative	More aggressive ESCO initiative
Local Government Facilities	Current modest effort	Extend ESCO model to local level	More aggressive ESCO initiative
Building Energy Codes	IECC 2006 and ASHRAE 2004; update to IECC 2009	Adopt IECC 2012 (or 30% beyond IECC 2006)	Same as Scenario Two plus 50% by 2020
Appliance Efficiency Standards	Federal standards from EISA 2007, DOE revises standards to minimize lifecycle costs (LCC)	Same as Scenario One plus additional state standards	Same as Scenario Two
Energy Efficiency RD&D Initiative	None	None	Energy efficiency RD&D initiative
Consumer Education and Outreach***	SCC-directed initiative	Expanded SCC-directed initiative	Same as Scenario Two
Low-Income Efficiency Programs***	Current policies	Expanded low-income programs	Same as Scenario Two

* CHP and manufacturing initiative are included in the EERS.
**The assessment of demand response potential is covered in the next chapter and in Appendix D.
*** These policies/programs are included in the policy recommendations, though ACEEE does not estimate costs and electricity impacts.

Energy Efficiency Policy Scenario Results

This section describes results for each of the energy efficiency policy scenarios, including estimated electricity savings and peak demand impacts from efficiency in 2015 and 2025. Descriptions of the policies and recommendations are provided next and more detailed results are shown in Appendix B. The demand response potential, impacts on peak demand, and policy recommendations are covered in the next section of the report and in Appendix D.

Scenario 1—Low Case Energy Efficiency

The estimated electricity savings under the low case scenario are shown by policy/program in Table 8. Under this scenario, Virginia sets a savings target, or EERS, of 10% (of 2006 electricity consumption) by 2022, which is equivalent to a savings of about 11,000 GWh. Accounting for savings from building code upgrades and federal appliance standards under this low case scenario, Virginia is estimated to reduce forecasted electricity consumption in 2025 by 12% and reduce peak demand by 11%. Estimated summer peak demand reductions are shown by sector in Table 9. This scenario represents total electricity savings equivalent to about 38% of the cost-effective resource potential identified in ACEEE's analysis.

Table 8. Low Scenario: Summary of Electricity Savings by Policy or Program

Annual Electricity Savings by Policy (GWh)	2015	2025	Total Savings in 2025 (%)
Energy Efficiency Resource Standard (EERS)	4,791	10,656	7%
Building Energy Codes	379	1,354	1%
Appliance Efficiency Standards (Federal)	2,147	4,741	3%
Total Savings	7,317	16,750	12%
Adjusted Electricity Load Forecast (GWh)	119,516	127,445	
Savings (% Reduction in Reference Case)	6%	12%	

Table 9. Low Scenario: Summary of Summer Peak Demand Reductions by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	644	1,479	5%
Commercial	751	1,735	5%
Industrial	176	391	1%
Total	1,572	3,606	11%
% Reduction in Reference Case	5.5%	11.0%	

Scenario 2—Medium Case Energy Efficiency

In the medium scenario, Virginia meets a more aggressive energy savings target (EERS), adopts more aggressive building codes, and establishes additional programs and policies to pursue more energy efficiency in the Commonwealth. Table 10 provides a summary of the annual electricity savings by policy for 2015 and 2025 and the percent savings relative to the reference case electricity forecast.

Compared to the total cost-effective energy efficiency resource available in 2025, discussed in the previous section and shown in Table 2, this policy scenario represents the penetration of about 63% of the available energy efficiency potential by 2025.

Table 10. Medium Scenario: Summary of Electricity Savings by Policy or Program (GWh)

Annual Electricity Savings by Policy (GWh)	**2015**	**2025**	**Total Savings in 2025 (%)**
Energy Efficiency Resource Standard (EERS)	6,477	18,437	13%
*CHP Incentives (included in EERS)**	*504*	*1,394*	*1%*
*State Manufacturing Initiative (included in EERS)**	*850*	*2,883*	*2%*
State Facilities	205	497	0.3%
Local Government Facilities	409	994	0.7%
Building Energy Codes	595	2,821	2%
Appliance Efficiency Standards (Federal)	2,147	4,741	3%
Appliance Efficiency Standards (State)	125	425	0%
Total Savings	9,957	27,914	19%
Adjusted Electricity Load Forecast (GWh)	116,876	116,281	
Savings (% Reduction in Reference Case)	8%	19%	

[*] *Savings from these policies are included in the EERS, though we show here their contribution to the savings targets.*

Table 11 shows estimated peak demand impacts from improved efficiency in this scenario. In total, efficiency policies and programs alone are estimated to reduce summer peak demand by 18% by 2025, relative to forecasted peak demand. These "permanent" peak impacts from efficiency are in addition to peak reductions from demand response efforts, which are discussed in the next section of the report and in Appendix D.

Table 11. Summary of Summer Peak Demand Reductions from Efficiency by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	784	2,153	7%
Commercial	1,194	3,318	10%
Industrial	191	577	2%
Total	2,169	6,048	18%

Scenario 3—High Case Energy Efficiency

The high case scenario represents a more aggressive effort for each of the policies analyzed in the medium scenario with the addition of a research, development, and deployment (RD&D) initiative. As shown in Table 12 and 13, under this scenario we estimate electricity savings of about 39,000 GWh by 2025, or a 27% reduction in forecasted electricity consumption, and a peak demand reduction of more than 8,000 MW in the same year, equivalent to a 25% reduction in forecasted peak demand. Again, these "permanent" peak demand reductions from efficiency are in addition to the potential for peak reductions from demand response. The high case scenario represents the penetration of 88% of the energy efficiency resource potential by 2025.

Table 12. Scenario 3: Summary of Electricity Savings by Policy or Program

Annual Electricity Savings by Policy (GWh)	**2015**	**2025**	**Total Savings in 2025 (%)**
Energy Efficiency Resource Standard	7,948	25,748	18%
*CHP Incentives (included in EERS)**	*1,572*	*3,829*	3%
*State Manufacturing Initiative (included in EERS)**	*925*	*3,467*	2%
State Facilities	307	746	1%
Local Government Facilities	614	1,491	1%
Building Energy Codes	424	2,884	2%
Appliance Efficiency Standards (Federal)	2,147	4,741	3%
Appliance Efficiency Standards (State)	125	425	0.3%
Energy Efficiency RD&D Initiative	29	3,083	2%
Total Savings	11,593	39,117	27%
Adjusted Electricity Load Forecast (GWh)	**115,240**	**105,078**	
Savings (% Reduction in Reference Case)	**9%**	**27%**	

**: Savings from these policies are included in the EERS, though we show here their contribution to the savings targets.*

Table 13. Summary of Summer Peak Demand Reductions by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	879	3,006	9%
Commercial	1,322	4,520	14%
Industrial	233	779	2%
Total	2,435	8,306	25%

Discussion of Policies

This section describes each of policies recommended and provides the assumptions used in the analysis for each scenario.

Energy Efficiency Resource Standard

An Energy Efficiency Resource Standard (EERS) is a quantitative, long-term energy savings goal for utilities or other entities (often coupled with a peak demand reduction target). Currently eighteen states have adopted some form of an EERS or have established legislation directing a state agency to set an energy savings target. This approach contrasts with many earlier state-legislated targets that were set in terms of funding levels or were short term. EERS targets are typically set independently of specific program, technology, or market targets in order to give utilities maximum flexibility to find the least-cost path toward meeting the targets (Nadel et al. 2006; ACEEE 2008).

Virginia has been among the leading eighteen states. In the spring of 2007, Governor Timothy Kaine inserted an enactment clause into the electricity "re-regulation" legislation (S.B. 1416) that directed the SCC to review a goal of reducing electricity use by 10% (of 2006 consumption) by 2022. The SCC was directed to review this possible energy savings target and make recommendations to the General Assembly. Our review of the various documents and interviews with leaders in the state suggest that some ambiguity exists as to the quantitative value of the savings target and whether the target is mandatory. The state needs to clarify this target. We also suggest that a companion peak demand reduction target should be set capturing both the permanent demand reductions from efficiency as well as the savings from demand response programs, as is discussed later in this report.

For our low case energy efficiency scenario, we assume that the Commonwealth establishes the 10% goal by 2022 discussed above as a binding target. This target applies to all electric providers—investor-owned utilities, municipal utilities, and rural electric cooperatives—though we would suggest that the coops and municipals should have a somewhat lower target because of their customer mix. Readers should note that a 10% savings of 2006 electricity use is equivalent to savings of about

11,000 GWh. Relative to 2022 *forecasted* consumption in the reference case (139,000 GWh) an 11,000 GWh reduction is equivalent only to an 8% reduction. In this low case scenario, savings do not extend past the 2022 target.

In our medium case energy efficiency scenario, we propose that Virginia sets a binding target of reducing electricity use 15% (of 2006 consumption) by 2022 and extends it to 2025 at an annual savings target of about 1% (relative to prior-year sales). Again, readers should note that a 15% savings target of 2006 electricity consumption (about 16,000 GWh) is equivalent to only a 12% reduction in *forecasted* consumption for 2022. By extending the target to 2025, savings grow to more than 18,000 GWh (see Table 10). In 2025, the EERS savings are equivalent to about a 13% reduction in reference case electricity consumption.

Savings to meet the EERS goals come from each of the three sectors, and various energy efficiency programs could contribute savings toward the target. For example, we estimate that the manufacturing initiative and CHP incentives, which are discussed next, contribute savings of about 3,100 GWh, or 17%, of the total 2025 savings target. These program savings come from a combination of both commercial and industrial sector efforts, contributing to 28% of the combined goals for these sectors alone.

Finally, our high case scenario assumes that an EERS sets binding annual savings targets (relative to prior-year sales) starting at 0.25% in year one, ramping up to 1.5% per year by year six, and extending to 2025 at the 1.5% per year target. This scenario is equivalent to a 19% savings target (of 2006 electricity consumption) by 2022. Under this scenario, total savings by 2025 reach nearly 26,000 GWh, which is equivalent to an 18% reduction in electricity consumption in the reference case.

Expanded State Manufacturing Initiatives

Based on discussions with a broad range of stakeholders involved with the manufacturing sector in Virginia, we propose a government/industrial collaborative we are calling the "Virginia Manufacturing Initiative." The goal of the initiative would be to address the three key barriers to expanded industrial energy efficiency identified by the stakeholders: the need for assessments that identify energy efficiency opportunities; access to industry-specific expertise; and the need for an expansion of the trained manufacturing workforce with energy efficiency experience.

The initiative would establish Centers of Excellence in the model of the U.S. Department of Energy's Industrial Assessment Center (IAC)[8] program, where university engineering students are trained to conduct energy audits at industrial sites. Centers could be established at the two main technical universities in Virginia, Old Dominion University (ODU) and Virginia Polytechnic Institute and State University (Virginia Tech). Expanding beyond the IAC model, these centers would partner with local community colleges and trade schools to bring their students into the larger network centered around the local Center of Excellence. These nearby satellite centers would extend training and associated materials to trade school and community college partners, and offer the opportunity to join the audits they conduct. The Virginia Philpott Manufacturing Extension Partnership (VPMEP) offers a connection to other regional educational centers that can provide outreach to manufacturing companies that might not otherwise be aware of energy efficiency programs.

This system would benefit three key groups: students interested in working in industrial energy management; businesses that need reliable, knowledgeable, and affordable consultation with regard to their energy usage; and the educational facilities and VPMEP outreach efforts that connect Virginia's manufacturers to the wealth of knowledge and proficiency that resides in the state.

IAC program and implementation results recorded over the last 20 years show that this program could identify 10-20% electricity savings per facility and achieve a 50% implementation rate. The

[8] For more information on the IAC program, visit: http://iac.rutgers.edu/.

number of audits per year would ramp up from 50 in the first year to 100 in the second and 200 in the third year and each following year. We calculate these 200 audits would represent roughly 10% of manufacturing energy use in Virginia. Because of time lag between the audit and implementation, we assume that investment and savings for each year would occur over three years, while program costs would begin in year zero. Program costs for the IAC program are about $1 for every $10 saved by industry. We factor in another $0.25 per $10 saved to account for additional education costs.

In the high case scenario, we expanded the number of assessments provided by the centers and complement these program offering with economic development incentives. As in many states, Virginia offers economic development incentives designed to encourage business owners to make improvements and invest in their facilities. Investments in energy efficiency count as applicable investments for many of these programs in Virginia. The *Virginia Economic Development Partnership* does look at energy efficiency investments as capital improvements for its purposes, and thus they are eligible for such incentives. Similarly, the *Virginia Small Business Financing Authority*, which helps provide financing for large capital investment projects, also considers efficiency investments as eligible. These incentives include grants and loans for the capital improvements.

There are complementary policies that could leverage economic development programs to reduce Virginia's energy consumption:

- The Virginia Department of Housing and Community Development administers the state's *Enterprise Zones* (EZs), which encourage companies to invest in their properties to enhance their competitiveness, and focuses specifically on economically distressed areas. Businesses located within EZs can take advantage of the Real Property Investment Grant, which offers a cash grant of up to $250,000 for investment projects, including investments in energy efficiency improvements. Since EZs have strong workforce development requirements, encouraging businesses to participate in their local EZs by making energy efficiency investments can help create jobs as well.

- These programs can all be leveraged to help Virginia achieve the energy efficiency goals that might be set by an EERS. Virginia's economic policies are beginning to encourage energy efficiency: in 2007, the Virginia State Legislature passed a bill (S.B. 1051) allowing buildings that exceed the state's energy efficiency standards by 30% to be taxed at a lower rate than typical buildings. Each individual taxing locality must decide whether or not to create a special tax bracket for these efficient buildings. But to date, it appears that very few have done so. Virginia could be more aggressive in encouraging efficiency and spreading the word to the public that such investments are critical to the state's energy future.

- Designating areas as Energy Improvement Districts (EIDs) are one way that some cities have steered companies toward the energy efficiency investments that ultimately positively impact their bottom lines. EIDs can take many forms, but foremost in their design is the provision of both financial and technical assistance that businesses require as they prepare to think about making investments in energy efficiency. And some EIDs pool money together from participating companies to purchase large distributed generation systems and then share the energy created by the systems, as well.

Prioritizing energy efficiency in economic development schemes makes sense because energy efficiency can help companies become more profitable and thus increase their levels of employment and investment. Furthermore, Virginia is a highly business-friendly state, and has an economic development infrastructure that is strong and well connected to the business community. Using Virginia's multiple economic development entities to market and/or administer energy efficiency programs is one way that Virginia can get a head start on helping companies make the efficiency investments necessary to meet any EERS goals.

Combined Heat and Power Incentives

Experience over the past decade has shown that if a level playing field is created for CHP, it will thrive, as has been seen in Texas (Elliott et al. 2007b). ACEEE has identified five factors that contribute to creating a favorable market for CHP:

- Standard interconnection rules;
- CHP-friendly standby rates;
- CHP financial incentive programs;
- Output-based emissions regulations (OBR); and
- Inclusion of CHP/waste heat recovery in a state RPS or EERS.

While interconnection guidelines are pending in the state (according public documents released by the Virginia State Corporation Commission's Division of Economics and Finance), the state otherwise has not actively supported CHP. This lack of policies effectively discourages CHP because it creates greater hurdles to deployment and thus adds to the overall project costs and timelines. Currently in Virginia there are only 9 operating CHP plants totaling 322 MW of capacity (see Appendix E for more details). We suggest that Virginia undertake a review of regulatory policies and work to encourage the appropriate authorities to move forward with policies that will foster a friendlier environment for CHP.

There are several areas in which state-level agencies could work to encourage greater CHP deployment:

1. *Interconnection*—The first is to establish standard interconnection rules that explicitly outline the steps required to interconnect CHP systems to the electric grid. According to the Virginia State Corporation Commission's Division of Economics and Finance, the state is considering interconnection rules for distributed generation, which often includes CHP. For interconnection rules to encourage CHP, they typically delineate particular system size categories, and combine particular review processes and fees that scale up as system sizes increase. They also explicitly name CHP as an eligible group of technologies, and provide system owners with a list of simple, transparent steps and easily navigable forms to apply for interconnection with the local utility. Some states also list specific manufacturers and models of CHP systems that have been approved for interconnection.

2. *Incentives*—Secondly, Virginia could develop incentives that encourage the deployment of distributed generation such as CHP. Some states shape these incentives as favorable property tax treatment, which are allocated to the portion of the property covered by a CHP system. Other states provide sales tax incentives based upon the size and output of CHP systems. These of course help reduce the overall cost of operating a CHP system and thus work to encourage deployment.

3. *Output-Based Emissions Regulations*—To encourage CHP deployment, many states also develop output-based emissions regulations (OBR), as opposed to emissions regulations based upon fuel input. OBRs take into account the fact that CHP systems produce more useful energy with their fuel inputs than other systems, and so give credit to the useful thermal output produced by CHP systems. Total emissions are calculated based upon system output, as opposed to fuel input. In this way, OBRs encourage CHP deployment.

4. *Include CHP in EERS*—Finally, states that wish to encourage deployment of CHP and other forms of clean distributed generation often include these technologies as eligible resources for their Renewable Portfolio Standards or EERS (discussed above). Allowing highly efficient CHP systems to explicitly count towards the proposed Virginia EERS would also increase the deployment of CHP.

These steps, which will lead to regulatory certainty, will reduce the effective cost of CHP projects. In the medium efficiency policy scenario, we project that these steps will reduce the effective cost of

CHP projects by $500/kW installed. Based on the market penetration scenario of EEA's analysis, a $500/kW incentive can result in additional CHP peak demand capacity of about 240 MW by 2025, equivalent to 1,400 GWh or a 1% reduction in overall electricity consumption.

CHP also represents a low cost source of efficiency reductions, particularly in the commercial sector. We thus suggest that utilities be encouraged to participate in encouraging expanded CHP, which could lead to a $1,000/kW reduction in cost through project funding participation. As a result, we suggest that we could see 570 MW of peak demand capacity in this scenario with the $500/kW installed implicit cost reduction. This is equivalent to a 3% reduction in overall electricity consumption in 2025.

State and Local Facilities

Government facilities represent unique opportunities for Virginia to implement energy-efficient practices saving the tax payers money while leading by example in advancing efficiency as Virginia's "first fuel." The Commonwealth has nearly one hundred facilities that report energy consumption costs to the Department of Mines, Minerals, and Energy (DMME). Virginia incorporates several different programs in order to promote efficiency among its agencies, including energy service performance contracting (ESPC) (Walz 2008).

The Federal Government and a number of other states use ESPCs to implement energy efficiency projects. An Energy Service Company (ESCO) can serve a number of needs in a project, including:

- Identifying and evaluate the energy savings opportunities;
- Developing the technical details of the project;
- Managing the design, installation, and commissioning;
- Arranging financing, though in some case the state may play this role (Birr 2008);
- Training staff and provide maintenance services; and
- Guaranteeing the savings will cover the project costs (KCC 2008).

The energy savings are used to repay this project cost as shown in Figure 14 (KCC 2008; Birr 2008). This model has proven highly effective in many places both in terms of delivering energy savings and in terms of cost effectiveness (Hopper, Goldman, and McWilliams 2005).

Figure 14. Graphical Representation of How an ESPC Project Is Financed

Source: KCC (2008)

The key to the success of these projects is to bring together a project structure that can facilitate all aspects of the program, as is the case in Pennsylvania. Under that program, approximately three full-time equivalent staff supported by an experienced contractor:

1. Pre-qualifies ESCOs that can participate in the program;
2. Reviews and negotiates the terms of the ESPC agreements since the government facilities

do not have the expertise to evaluate either the technical or contractual aspects of these projects; and

3. Reviews the completed projects to ensure that the projects are performing as agreed to in the contract.

Pennsylvania has been able to manage almost 50 projects each year, with total program and administrative costs of less than 2% of project costs (PA-GSA 2008; Birr 2008).

Virginia's EPSC program might be strengthened when compared to leading states such as Pennsylvania, Kansas, and Colorado, since it reaches only a portion of state facilities. A more robust structure and additional technical support might also be engaged. State agencies participate in efficiency programs, so significant additional energy efficiency opportunities still exist that could increase savings in state facilities. To address these opportunities, we recommend that Virginia expand its program, modeling the restructured program around the Pennsylvania experience drawing upon an expert consultant to complement the state agency staff (PA-GSA 2008). We also recommend that the Commonwealth draw upon a national organization that has been formed with DOE support, the *Energy Services Coalition,*[9] which supports state and other entities in implementing ESPC programs (ESC 2008).

We also suggest that the program be extended to local government facilities. We understand that local governments can encounter bond rating problems with ESPC contracts because the rating entities view them as unsecured loans. To address this problem, the state should consider establishing a bonding authority that would finance these EPSC projects, with the project funding paid back by the energy savings.

Based on this model, we assume that state and municipal buildings in Virginia can achieve an average of a 20% reduction in projected 2025 electricity sales, with a 50% participation rate in the medium case policy scenario. In the high case scenario, we assume a 75% participation rate by 2025. We assume the average investment costs are consistent with the projected efficiency resource cost for the commercial sector identified in this report and that the program and administrative costs including evaluation, measurement, and verification are 2% of project cost, somewhat higher than for the Pennsylvania General Service Administration program (Birr 2008). Under these assumptions, we estimate savings in the medium case of about 600 GWh by 2015 and about 1,500 GWh by 2025 from state and local facilities, or a 1% reduction in electricity consumption in 2025. In the high case scenario, savings grow to 2,200 GWh by 2025, a 1.5% reduction in projected electricity consumption.

Building Energy Codes

Building energy codes are a foundational policy to ensure that efficiency is integrated into new buildings in Virginia. If efficiency is not incorporated at the time of construction, the new building stock represents a “lost opportunity” for energy savings because efficiency is otherwise difficult or expensive to install after a building is built.

In 2008, Virginia will add an estimated 30,000 homes or 1% to its existing housing stock of about 3 million (Economy.com 2008). This is a downturn from recent annual additions of about 2% of the housing stock (2000-2006), though still represents the largest source of growth in home energy usage and therefore a critical opportunity for increased energy efficiency in the Commonwealth. New commercial buildings are expected to be built at a similar pace to residential homes based on forecasted employment (Economy.com 2008).

Virginia, which recently adopted the International Energy Conservation Code 2006, has already begun efforts to review the IECC 2009 and is likely to adopt it, going into effect in 2011 (Rodgers 2008). For this analysis, we modeled the following scenarios:

[9] For more information on the Energy Services Coalition, see http://www.energyservicescoalition.org/about/index.html.

- In our low case scenario, IECC 2009 is adopted in 2009, effective in 2011, reducing energy usage 15% in new residential and non-residential buildings compared to the 2006 IECC and ASHRAE 90.1-2004. This scenario would result in savings of about 1% of projected electricity sales in 2025.
- In our medium case scenario, a second new state code, the IECC 2012, is adopted and goes into effect in 2015, reducing energy use by 30% from 2006 IECC and ASHRAE 90.1-2004. The 30% reduction is ASHRAE's savings target for the 90.1-2010 code. A proposal for 30% savings in residential buildings is now pending before the IECC. Adopting IECC 2012 would generate about 2,800 GWh of electricity savings, or 2% of projected electricity sales in 2025.
- Our high case scenario builds upon our medium case scenario to include the adoption of a new state code that becomes effective in 2020, reducing building energy use by 50% relative to 2006 IECC and ASHRAE 90.1-2004. This would yield savings of nearly 2,900 GWh in 2025.

The new building codes require a commitment by the state to enforce the higher standards. We assume enforcement of each code starts at 70% compliance in the first year, 80% in second year, and 90% in the third and subsequent years.

Appliance Efficiency Standards

Lighting and appliance standards, first authorized by Congress in the 1970s and legislated again in 1987, 1992, 2005, and 2007, have become a core energy policy for the United States, setting performance targets for dozens of common household and business products and systems. Individual states have played and continue to play an important role in advancing standards for the nation. In the 1980s, states' initiative in developing standards in the face of federal inaction led to the landmark National Appliance Energy Conservation Act of 1987 (NAECA). Since then, state enactment of standards on products not covered by federal law has led to many new federal standards.

In the low case scenario, we account only for savings from appliance standards that result from recent federally legislated appliance standards. These include standards set by the Energy Independence and Security Act of 2007 (EISA) and those that DOE are directed to establish. ACEEE estimated savings from about 30 products to determine the reduced electricity consumption attributed to the implementation of federal appliance standards (ASAP 2008). However, savings will not begin to accrue until 2010 for the vast majority of these products as the standards are not set to take effect until that date. Savings from federal appliance standards alone will reduce electricity consumption by about 2,150 GWh by 2015 and 4,700 GWh by 2025, or 3.3% of electricity sales in 2025.

In the medium and high case scenarios, we examined the additional savings that Virginia could realize should it choose to implement appliance standards on products beyond those covered by federal legislation. In estimating savings for these two scenarios, ACEEE analyzes appliance standards for an additional six products which would reduce consumption by an additional 125 GWh in 2015 and 425 GWh in 2025, or 0.3% of electricity sales in 2025 (ASAP 2008). In our medium and high case scenarios, total savings amount to about 2,300 GWh in 2015 and 5,200 GWh in 2025, or 3.6% of forecasted electricity sales in 2025.

Research, Development, and Deployment (RD&D)

Several states support active research, development, and deployment (RD&D) programs designed to develop technologies appropriate to each state's climate, economy, and other resources. For more information, see the Association for State Energy Research and Technology Transfer Institutions (www.asertti.org). In the high case energy efficiency policy scenario, we assume a policy initiative that establishes a state RD&D entity to undertake Virginia-specific research into energy efficiency technologies and to help develop energy efficiency jobs and businesses in Virginia. In order to meet long-term savings goals, RD&D of new technologies is critical to sustain continued improvements in energy efficiency after currently commercialized technologies and practices are widely adopted.

Based on successful programs in New York and other states, we estimate that an RD&D effort in Virginia could reduce electricity consumption by about 3,000 GWh in 2025, or 2% relative to the reference case.

Consumer Education and Outreach

The majority of policies discussed in this report will require a few years to come to fruition. To catalyze efficiency efforts in the state, we recommend that Virginia consider engaging in a public education initiative to encourage energy-saving practices. The SCC has been directed to look into providing this service to the public. This could be accomplished through a wide array of media to promote calls by the governor for investments in energy efficiency and conservation. ACEEE modeled a program for Florida that was based on an existing short-term public outreach program in California and found that Florida could save 3% of projected electricity sales and 5% of peak demand in 2010 with such a program.[10] These public action programs are by their nature of limited duration, being effective for a few years at most. As a result, significant savings were realized in the first few years but quickly dissipated thereafter. While the direct impacts of these efforts may have limited long-term impact, sending signals to consumers and supplying them with information about efficiency programs establishes a solid foundation for the introduction and efficacy of these and other policies.

Public education should also be an integral part of any long-term efficiency program efforts. The states with the most effective programs typically invest in significant communications efforts, where leaders including the governor appear prominently in public media. The value of leadership in this regard cannot be overstated.

Low-Income Efficiency Programs

Addressing the energy needs of low-income households is crucial when implementing efficiency programs as these households on average spend a greater percentage of their income on energy relative to their wealthier counterparts. Programs like the Low-Income Home Energy Assistance Program (LIHEAP) provide households with additional funds they can put towards paying energy bills or making efficiency improvements to their homes. ACEEE recognizes this need and recommends that Virginia consider implementing its own low-income assistance programs to assuage these households' economic concerns, especially in the wake of rising fuel costs.

Although short-term relief is important, funding energy bills without concomitantly promoting and implementing efficiency measures precludes any long-term benefits, meaning that more state and local funds will be consumed than is necessary since household energy bills will not fall in the future. Thirteen percent of Virginians heat their homes with oil and 34% heat their homes with natural gas (EIA 2003), so these households, especially those occupied by low-income households, are particularly vulnerable to high fuel costs. Focusing on home weatherization programs provides short-term and, more importantly, long-term benefits, guaranteeing that future energy bills will drop and remain low. These programs can also incorporate educational and job training components, which inform the public on how to maximize their energy savings while giving individuals the knowledge and skills to take these ideas and diffuse them throughout their communities.

We also recommend introducing programs for middle-income households that do not qualify for low-income assistance, as high fuel costs have a substantial impact on their economic security as well. Programs like low cost financing allow households in this income bracket to afford efficiency improvements, like home weatherization. Locally focused efficiency suites can also have a

[10] In 2001, California and other Western states used such programs to achieve substantial savings and help weather their energy crisis with minimum disruptions. For example, an evaluation of the California program found that it reduced energy use by 6.7% in the summer of 2001 and peak demand by about 11% relative to the year before (Global Energy Partners 2003). And significant benefits persisted for multiple years, especially as approximately 60% of the actions involved technology investments with a two-year payback. The Florida program was conservatively assumed to be only half as effective.

substantial impact on energy consumption, such as direct installation of energy-efficient products and the identification of homes requiring large-scale efficiency improvements. We assume that these types of programs would be part of the state EERS and, therefore, are not counted separately.

Costs and Benefits in Medium Case Energy Efficiency Policy Scenario

In this section, we estimate the costs and benefits of the medium case energy efficiency policy scenario to determine overall cost-effectiveness. There is no single answer to whether energy efficiency is cost-effective, but rather there are multiple perspectives analysts take to determine cost-effectiveness. Here, we examine the medium policy scenario using two cost-effectiveness tests, the Total Resource Cost (TRC) test and the Participant Cost test. We do not do an equivalent analysis for the demand response policy scenario, which is discussed in the next section, due to the difficulty in evaluating the dollar savings benefits to consumers from demand response measures.

The costs needed to run the efficiency policies and programs recommended for the medium scenario and achieve the estimated electricity savings include both the investments in efficient technologies or measures and the administrative or marketing costs to run programs and administer policies. The technology investments might include any combination of incentives paid to customers or direct customer costs. See Table 14 for a breakdown of the estimated costs in the medium scenario. See Appendix B for estimates of total costs in the low and high case scenarios.

Table 14. Annual Energy Efficiency Costs in Medium Scenario (Millions of 2006$)

	2010	**2015**	**2020**	**2025**
Customer Investments	$105	$414	$488	$483
Incentives Paid to Customers	$67	$132	$152	$148
Admin/Marketing Costs	$16	$30	$35	$36
Total Costs	$187	$575	$676	$668

Note: These costs are undiscounted and shown in real, 2006$.

The chapter on macroeconomic impacts uses these cost assumptions to estimate impacts of the efficiency policies on the economy, including overall benefits to customers. Here, we report a net present value (NPV) analysis of costs and benefits to society and to participants. The next two tables (see Table 15 and Table 16) show results from the TRC test and the Participant Cost Test, respectively, with a breakdown of total costs and benefits (present value in 2006$) by policy type and by sector over the study time period (2009–2025). Readers should note that although the study time period ends in 2025, savings from the efficiency measures persist over the lifetime of each specific measure. Accounting for these additional savings beyond the study time period would yield additional benefits and therefore a higher benefit/cost ratio.

The TRC test, as shown in Table 15, evaluates the net benefits of energy efficiency to the region as a whole. This test considers total costs, including investments in efficiency measures (whether incurred by customers or through incentives) and administrative or marketing costs. Benefits in the TRC test are the avoided costs of energy, or the marginal generation costs that utilities avoid by reducing electricity consumption through energy efficiency. The avoided energy resource costs were determined by the analysis by Synapse Energy Economics (see Appendix A). The TRC test, which shows an overall benefit-to-cost ratio of 1.9, suggests a net positive benefit to Virginia as a whole from implementing these efficiency programs and policies. When accounting for benefits over the lifetime of the efficiency measures, the ratio increases to 2.6.

The Participant Cost Test, as shown in Table 16, takes the perspective of a customer installing an energy efficiency measure in order to determine whether the participant benefits. The costs are the costs to customers for purchasing or installing energy efficiency and the benefits are the savings on customers' electricity bills due to reduced consumption plus any incentives paid to the customers. Again, this analysis only takes into account costs and benefits through 2025, even though customer savings on electric bills would continue well past 2025. Even without accounting for the benefits that persist after measures installed in 2025, the Participant Cost Test yields a positive benefit to participants, with a 2.4 benefit/cost ratio. If accounting for savings that persist over the measure lifetime, this ratio increases to 3.3.

See Figure 15 for a representation of the results using three different discount rates.

Table 15. Total Resource Cost (TRC) Test (2009–2025)

By Policy/Program	NPV Costs	NPV Benefits	Net Benefit	B/C Ratio
Energy Efficiency Resource Standard (EERS)	$ 3,468	$ 6,949	$ 3,481	2.0
*CHP Supporting Policies**	*$ 234*	*$ 530*	*$ 296*	*2.3*
*State Manufacturing Initiative**	*$ 541*	*$ 954*	*$ 413*	*1.8*
State Facilities	$ 57	$ 201	$ 143	3.5
Local Government Facilities	$ 114	$ 401	$ 287	3.5
Building Energy Codes	$ 604	$ 849	$ 245	1.4
Appliance Efficiency Standards	$ 1,393	$ 2,033	$ 640	1.5
Total	**$ 5,636**	**$ 10,433**	**$ 4,797**	**1.9**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 2,734	$ 3,697	$ 963	1.4
Commercial	$ 2,092	$ 5,337	$ 3,246	2.6
Industry	$ 811	$ 1,398	$ 587	1.7
Total	**$ 5,636**	**$ 10,433**	**$ 4,797**	**1.9**

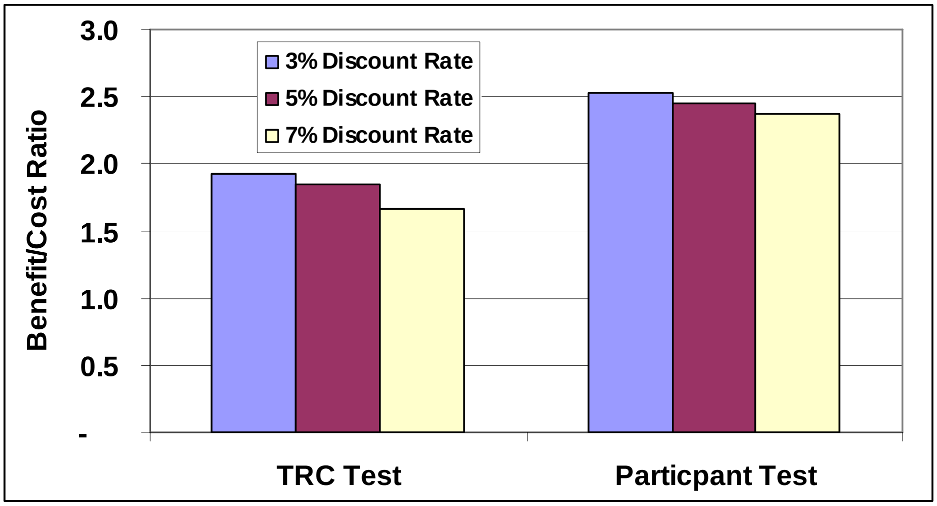
*Note: These two policies are included in the costs and benefits of the EERS.

Table 16. Participant Cost Test (2009–2025)

By Policy/Program	NPV Costs	NPV Benefits	Net Benefit	B/C Ratio
Energy Efficiency Resource Standard (EERS)	$ 3,159	$ 9,054	$ 5,895	2.9
*CHP Supporting Policies**	*$ 228*	*$ 719*	*$ 491*	*3.1*
*State Manufacturing Initiative**	*$ 523*	*$ 781*	*$ 258*	*1.5*
State Facilities	$ 56	$ 224	$ 168	4.0
Local Government Facilities	$ 112	$ 447	$ 335	4.0
Building Energy Codes	$ 591	$ 975	$ 384	1.7
Appliance Efficiency Standards	$ 1,392	$ 2,285	$ 894	1.6
Total	**$ 5,310**	**$ 12,985**	**$ 7,675**	**2.4**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 2,547	$ 5,289	$ 2,742	2.1
Commercial	$ 1,973	$ 6,493	$ 4,520	3.3
Industry	$ 790	$ 1,203	$ 413	1.5
Total	**$ 5,310**	**$ 12,985**	**$ 7,675**	**2.4**

*Note: These two policies are included in the costs and benefits of the EERS.

Figure 15. Results of TRC and Participant Cost Tests Using Three Discount Rates



ASSESSMENT OF DEMAND RESPONSE POTENTIAL

This section defines Demand Response (DR), assesses current DR activities in Virginia, uses benchmark information to assess DR potential in Virginia, and concludes with policy recommendations that could foster DR contributing appropriately to the resource mix in Virginia that can be used to meet electricity needs. Potential load reductions from DR are estimated for a suite of DR programs that represent the technologies and customer types that span a range of DR efforts (as is discussed below and in Appendix D.

Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions and enhance operating reserves to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs and represent an important element that can be integrated into least-cost resource plans.

DR resources are usually grouped into two types: (1) load-curtailment activities where utilities can "call" for load reductions; and (2) price-based incentives that use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and electric systems face the substantial investment in overall electric infrastructure needed to support new generation resources.

The summary of DR potential presented in Table 17 focuses on load-curtailment and backup generation and does not include savings resulting from price-based incentives. Residential load-curtailment typically involves direct load control (DLC) of air conditioners—although this can also cover appliances—as well as temperature offsets, which increase thermostat settings for a certain period of time. Commercial and industrial applications of DR focus on load control of space conditioning equipment; however, this depends on customer size: self-activated load reductions are usually more prudent for larger customers. Backup generation for commercial and industrial applications involves generators with start-up equipment that allows them to come online with short notice from utilities, relieving the additional demand on the system during peak hours.

Rationale for Investigating Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability**—DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs**—DR may be less expensive per megawatt than other resource alternatives.
- **Manage operational and economic risk through portfolio diversification**—DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- **Provide customers with greater control over electric bills**—DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events.
- **Address legislative/regulatory interest in DR**—Electric utility legislation enacted in April 2007 set a statutory goal for the Commonwealth to save 10% of its total 2006 electricity sales by 2022 (H.B. 3068 and S.B. 1416, commonly referred to as the electricity “re-regulation” legislation). While the legislation focuses on an energy consumption goal, the Virginia State Corporation Commission Energy Efficiency Working Group has stated that reducing peak demand is also an important consideration (SCC 2008c).

Commonwealth of Virginia—Background

Virginia’s service territory is characterized by high population and load growth, the majority of which is attributable to new residents. Since 2000, the Commonwealth has grown in population by 8%, compared to 6% for the United States as a whole. The impact of population growth on electricity demand is compounded by the fact that *electricity consumption per customer* has risen dramatically in the past several decades. PJM projects that the peak demand for electricity in Dominion’s service area will grow by almost 1,800 MW in just five years—the equivalent, in PJM’s estimation, of adding one million homes to the system. Dominion’s own studies project it will need 4,000 MW of new capacity in ten years. This growth will strain Virginia’s electric system (Dominion 2008).

Virginia has had some of the lowest electricity rates in the county and, until recent years, has had adequate capacity to meet the Commonwealth’s electricity needs. As a result, interest in energy efficiency and DR in Virginia has been limited. Current conditions are changing. New capacity and infrastructure investments are needed. Increasing electricity costs stem from a combination of rising consumption (necessitating new investment in generation and transmission), increases in fuel costs, and the potential for additional environmental restrictions. The elimination of price caps and potentially higher fuel prices will increase the importance of assessing future resources and DR potential.

Role of Demand Response in Virginia’s Resource Portfolio

The DR capabilities deployed by Virginia utilities can become part of a long-term resource strategy that also includes resources such as traditional generation resources, power purchase agreements, options for fuel and capacity, and energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allowing Virginia customers to better manage their electricity costs.

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has led to a number of states and utilities piloting and implementing a Smart Grid, sometimes referred to as Advanced Metering Infrastructure (AMI). Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability, and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion deployed a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods.

Assessment of Demand Response Potential in Virginia

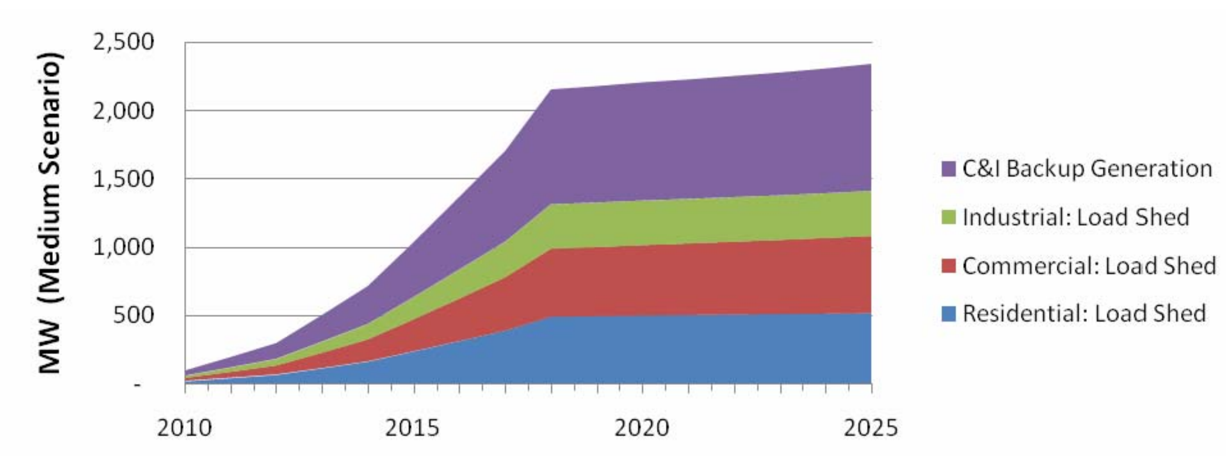
This assessment indicates that system peak demand can be reduced by approximately 7.2% or 2,209 MW in 2020 with the medium scenario. A more aggressive high scenario would result in a 10.8% or a 3,322 MW reduction in peak demand. These assessments assume that initial DR program designs are developed in 2009 with implementation starting in early 2010. This provides for a ten-year rollout of the DR efforts. It is expected that the first two years of implementation after the initial DR program designs will be used to fine-tune the programs.

Table 17 shows the resulting load shed reduction assessment for Virginia, by sector, for years 2015, 2020, and 2025, and Figure 16 shows the resulting load shed reductions possible for Virginia, by sector, from year 2010, when load reductions are expected to begin, through year 2025. These estimates reflect a sustained level of effort, and utilities are recommended to set targets for the high scenarios. These estimates include assumptions regarding energy and peak demand growth rates, participation rates, and program design, among others. These assumptions take into account the increased energy efficiency activities that will be occurring during this same period. The data inputs and assumptions are discussed in Appendix D. The overall trend in the DR program potential impacts in Table 17 and Figure 16 indicates that DR MWs grow rapidly through the end of 2018 as these years represent major implementation efforts. After 2018, the growth in DR MWs roughly follows the forecasted growth in peak demand.

Table 17. Summary of Potential DR in Virginia, By Sector, for Years 2015, 2020, and 2025 [a]

	Low Scenario			Medium Scenario			High Scenario		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Residential: Load Shed (MW)	143	299	310	238	499	516	333	699	723
Commercial: Load Shed (MW)	88	194	213	235	517	567	441	970	1,063
Industrial: Load Shed (MW)	72	145	147	162	327	331	289	582	588
C&I Backup Generation (MW)	302	639	698	402	865	930	503	1,082	1,163
Total DR Potential (MW)	605	1,288	1,367	1,038	2,209	2,345	1,566	3,332	3,537
DR Potential as % of Total Peak Demand (30,065 MW)	2.1%	4.2%	4.2%	3.6%	7.2%	7.2%	5.4%	10.8%	10.8%
[a] See Appendix D for underlying data and assumptions.									

Figure 16. Potential DR Load Reduction in Virginia by Sector (MW)



Recommendations

Key recommendations for fostering the growth of DR in Virginia are summarized below, with greater discussion contained in Appendix D. These recommendations are not listed in order of importance but they include:

1. Appropriate financial incentives for Virginia utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators.
2. Integrate DR programs with the delivery of EE programs.
3. Implement load reduction programs in he early years used as a shakeout period for program design and adapt the programs to achieve the projected impacts. This assessment is based on established technologies and program designs.
4. Implement programs focused on achieving firm capacity reductions. The following programs, which can be designed within a 12-month period, include:
    a. Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).[11]
    b. Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.

[11] This approach is currently being used successfully by LGE Energy.

   c. Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
   d. Aggressive enrollment of backup generators in DR programs.
5. Pricing should form the cornerstone of an efficient electric market. Daily time-of-use pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. Another example is "critical peak pricing," where utilities or system operators utilize an automated system to cut back electricity consumption amongst their customers in response to periods of unusually high demand.
6. Customer education should be included in DR efforts (as also recommended by the SCC Sub-group 3 (SCC 2007). There is a perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight
7. Increase clarity and coordination between the Federal and State agencies and programs (as also recommended by the SCC Sub-group 3 (SCC 2007). 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.

MACROECONOMIC IMPACTS: IMPACT OF POLICIES ON VIRGINIA'S ECONOMY, EMPLOYMENT, AND ENERGY PRICES

In this section, we present the results of an assessment of the macroeconomic impacts of the medium case energy efficiency policy scenario recommendations on the economy of Virginia.[12] These policies result in a substantial reduction in consumer energy bill spending, while creating a significant number of new jobs. In fact, continued investments in energy efficiency resources would continue to yield energy resource benefits for many years into the future beyond our analysis period. The state therefore has the opportunity to transition its energy markets to a more sustainable system of production and consumption to benefit consumers and the environment.

Methodology

This economic evaluation is undertaken in three steps. First, we calibrate ACEEE's economic assessment model called DEEPER (Dynamic Energy Efficiency Policy Evaluation Routine) to reflect the economic profile of the Virginia economy (Laitner and McKinney 2008b), incorporating the anticipated investment patterns that are assumed in the reference case (e.g., construction of new electric power plants projected in the forecast). Second, we transform the set of key efficiency scenario results from the policy analysis above into inputs for the economic model. The resulting inputs include such parameters as:

1. The level of annual program spending that drives the policy scenario;
2. The electricity savings that result from the various energy efficiency policies or the level of alternative electricity generation from onsite renewable and combined heat and power technologies; and
3. The capital and operating costs associated with those technology investments.

[12] We do not present macroeconomic impacts for the low and high policy scenarios, though readers can approximate impacts based on magnitude of energy savings in each of those scenarios compared to the medium scenario.

Finally, the model is run to check both the logic and the internal consistency of the modeling results. A detailed description of the economic model is presented in Appendix F.

Impacts of Recommended Energy Efficiency Policies

For each year in the analysis period, the change in a sector's spending pattern relative to the reference scenario was matched to the appropriate sectoral impact coefficient. These negative and positive changes were summed to generate the estimated net result shown in the series of tables that follow. Presented here are three sets of impacts for the benchmark years of 2015 and 2025, which were estimated using the investment and savings results from the policy scenario.

Table 18 presents the estimated change in Virginia's electricity production patterns from the efficiency scenario compared to the reference case, along with the investment and program costs required to achieve these savings. These patterns are driven by the energy efficiency policy initiatives outlined in the policy analysis presented above (a detailed table with data for the years 2010, 2015, 2020, and 2025 can be found in Appendix F).

Table 18 also presents the changes in consumer expenditures that result from these policies. While the first row in the table presents the full cost of the energy efficiency policies, programs, and investments, the utility customers will likely borrow a portion of the money to pay for these investments. Thus, "annual consumer outlays," estimated at about $700 million in 2015 and rising to $950 million in 2025, include actual "out-of-pocket" spending for programs and investments, along with money borrowed to underwrite the larger technology investments. The annual electricity bill savings reported in the table are a function of reduced electricity purchases from the Virginia utilities at the initial electricity prices in a given year.

Table 18. Changes in Virginia Electricity Production and the Financial Impacts from the Medium Energy Efficiency Policy Scenario: 2015 & 2025*

(Millions of 2006 $)	**2015**	**2025**
Annual Total Cost**	$575	$668
Savings Relative to Reference Case:		
Cumulative Savings (GWh)	9,957	27,914
Cumulative Savings (%)	7.9%	19.4%
(Millions of 2006 $)		
Annual Consumer Outlays	$698	$947
Annual Electricity Savings***	$866	$2,448
Annual Price of Electricity Savings***	$312	$681
Annual Net Consumer Savings	$480	$2,182
Cumulative Net Energy Savings	$1,091	$15,189

* 'Annual' refers to the given benchmark year. 'Cumulative' is the sum total from previous years beginning with 2008.
**Annual Total Costs include administrative costs to run programs, incentives provided to consumers, and investments in energy efficiency devices (investments are from both utilities and consumers).
***Annual Electricity Savings is the amount of electricity that consumers save and its associated value in lowered energy bills. Annual Price of Electricity Savings is additional savings due to reductions in the *price* of electricity. Since consumers are using less electricity, demand falls, so then price.

Energy efficiency policies provide resources that enable consumers to make investments that change the patterns of electricity consumption and production. Total costs include program spending, incentives, and investments of $575 million in 2015, which when combined with consumer borrowing totals about $700 million. The cumulative impacts on electricity production are quite large in 2015, reducing electricity demand by about 10,000 GWh (8% below reference case demand). In 2015, the reduced electricity consumption saves consumer nearly $900 million gross in electricity costs. Total costs rise to $670 billion dollars in 2025, or about $950 million including consumer borrowing. The cumulative impact of activities over the time horizon steadily reduces the demand for conventional electricity generation so that by 2025 energy efficiency displaces the forecasted electricity production by about 19%. These investments result in consumer savings of $2.4 billion gross in lowered electricity costs.

Our analysis also explores the impact of reduced consumption on electricity prices. Previous research has shown that in tight markets, small changes in energy demand can have large impacts on energy prices, particularly for natural gas (see Elliott and Shipley 2005; Elliott 2006). The changed electricity production patterns, including both reduced electricity demands and efficiency technology investments, produces a negative adjustment in the electricity supply costs due to the lower capital and operating expenditures associated with the energy efficiency policy scenario. Essentially, the efficiency policies reduce wholesale electricity prices. Our estimates of these effects are shown in Table 18 as “Annual Price of Electricity Savings.” As shown, we estimate that consumers can save an additional $300 to $700 million gross annually, relative to the reference case, due to these price effects.

The category of annual net consumer savings estimates the consumers’ total savings from both lower electricity consumption and lower prices, minus consumer outlays. In 2015, electric customers save about $900 million in reduced electricity consumption and $300 million in reduced electricity prices, and spend $700 million in outlays for a net consumer gain of about $500 million. In 2025, net annual consumer savings grows nearly five-fold from the 2015 value to $2.2 billion. The last row in the table shows cumulative net consumer savings, which sums the annual net savings over the study time period. In 2015, net cumulative savings are $1 billion and grow to $15 billion by 2025.

Once each of the net sector spending changes has been evaluated for a given year, the DEEPER model then evaluates impact on jobs and wages sector-by-sector, and evaluates their contribution to the state’s GSP. Table 19 highlights the net impacts, again for the benchmark years 2015 and 2025.

Table 19. Economic Impact of Energy Efficiency Investment in Virginia

Macroeconomic Impacts	2015	2025
Jobs (Actual)	675	9,820
Wages (Million $2006)	63	583
GSP (Million $2006)	202	882

The analysis estimates a net contribution to the Virginia employment base as measured by full-time jobs equivalent of 675 in 2015 and 9,820 in 2025 (see Table 19 and Figure 17. In Virginia, the electric services sector utilizes 2.68 jobs for every $1 million investment. But, sectors vital to energy efficiency improvements, like construction, utilize 7.8 jobs per $1 million invested. Once job gains and losses are netted out in each year, the analysis provides the net annual employment benefit of the policies that impacts the larger Virginia economy. Figure 17 provides year-by-year impacts on net jobs in Virginia. The increase in jobs and the changes in job mix result in a net gain to the state's wage and salary compensation, measured in millions of 2006 dollars, as shown in Table 19 and Figure 18.

Figure 17. Net Job Impacts for Virginia (2008-2025)

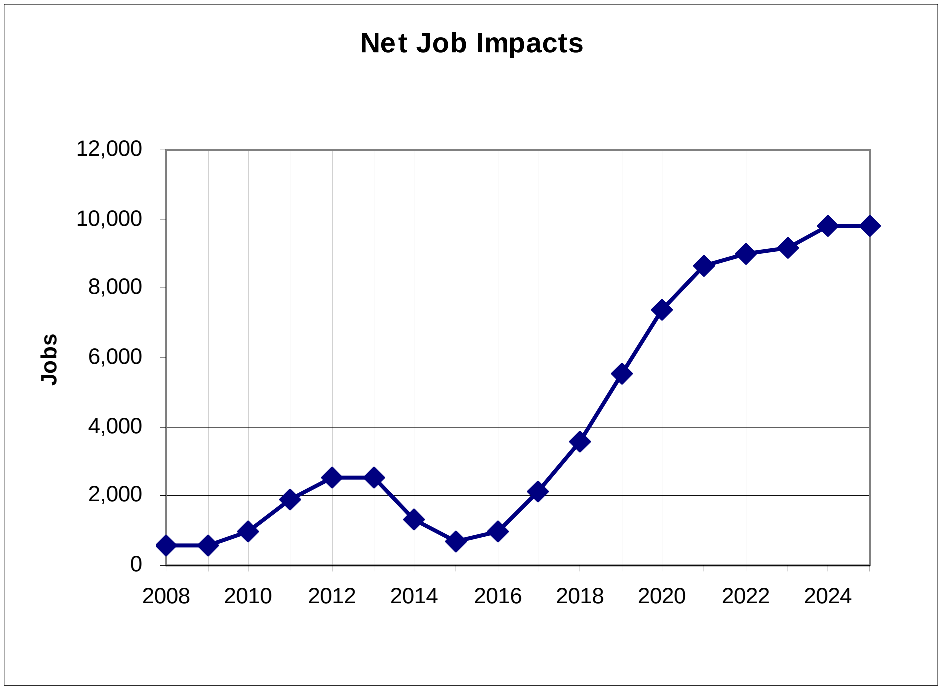
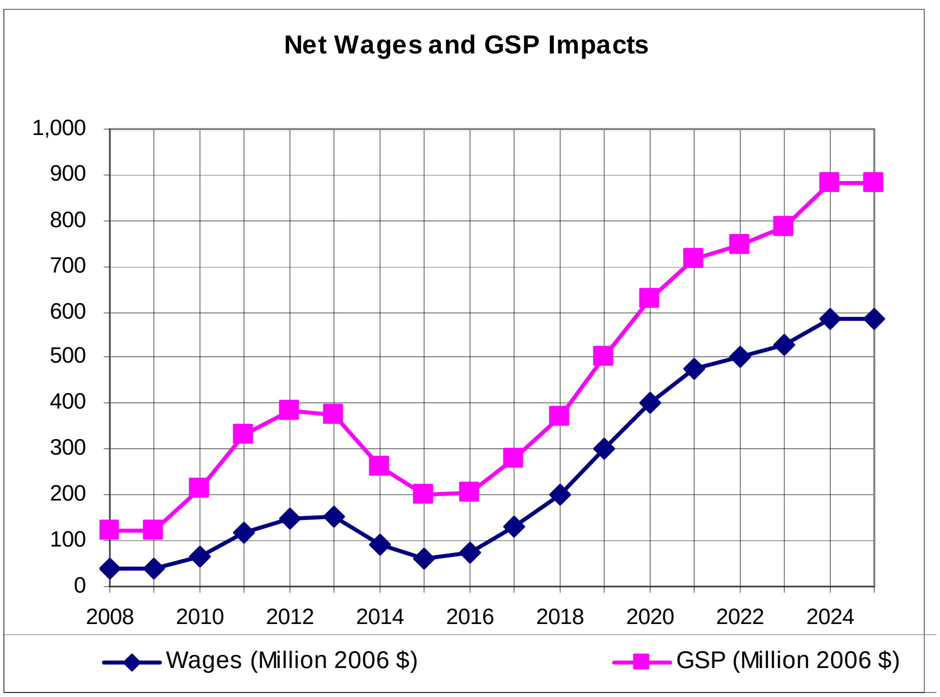


Figure 18. Wages and Gross State Product Impacts for Virginia (2008-2025)



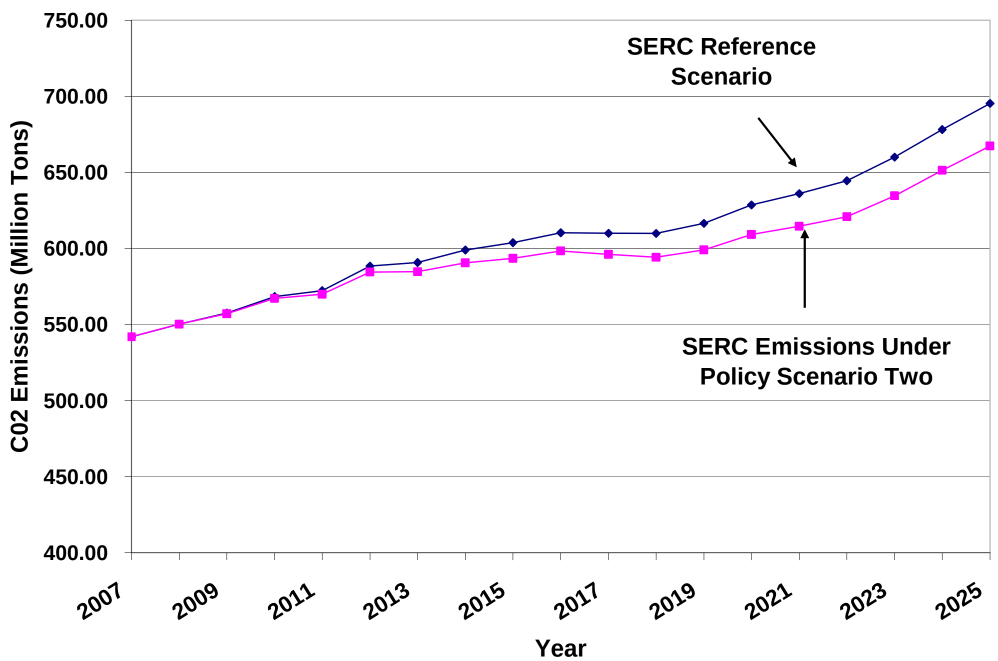
Early program stimulus and investments drive an increased economic impact, creating an average of 1,500 jobs each year in the first six years of the study. These investments increase wages and GSP throughout Virginia (see Figure 18). Better, more efficient use of the energy supply reduces the need for imported energy, and keeps those revenues from leaking outside the state. The years 2014 through 2016 provide smaller increases in jobs, wages, and GSP. The reference case for this analysis included large investments in temporary power plant construction during this period without energy efficiency investments. During the period 2013-2018, the reference case's investments are higher relative to other years in the reference case, and by comparison make the policy case's investments appear to generate lower levels of economic returns.

Emissions Impacts in Policy Scenario

Meeting the demand for electricity through efficiency resources reduces electricity generation and thus any environmental impacts that would result can be avoided. Efficiency represents a cost-effective strategy to reduce global warming emissions. One caveat of the avoided emissions from efficiency that readers should note is that Virginia imports a significant share (about 30%) of its electricity from outside the state and therefore the avoided electricity is not directly attributable to specific power plants in Virginia but rather from the wholesale power market.

Policies from the medium energy efficiency scenario would reduce carbon dioxide (CO_2) emissions in the Southeast by 10 million tons in 2015 and 28 million tons in 2025, or 1.7% and 4% of total emissions in the region, respectively (see Figure 19). Through 2025, energy efficiency can reduce CO_2 emissions cumulatively by about 240 million tons. In 2006, Virginia accounted for just over 46 million tons of CO_2 emissions, almost 9% of regional emissions (EIA 2007a). Electricity savings from efficiency policies in Virginia would have an impact across the entire Southeast. We therefore estimate these CO_2 reductions from energy efficiency programs and policies relative to the entire region (see Appendix B.2 for discussion on the methodology).

Figure 19. SERC CO_2 Emissions in Reference Scenario and Policy Scenario Two

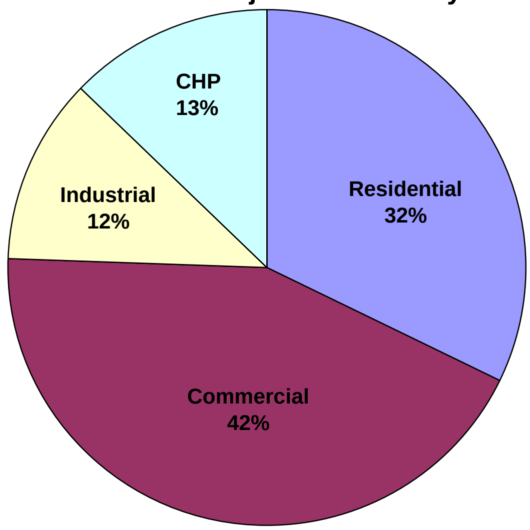


Summary of Findings

Energy Efficiency Resource Potential

ACEEE's assessment of cost-effective energy efficiency potential in Virginia estimates efficiency resources equivalent to about 30% of the electricity needs of the Commonwealth in 2025. Energy efficiency resources are identified across all sectors: residential, commercial, and industrial (see Figure 20), which highlights the critical point that all players in Virginia can make contributions to improve energy efficiency in the Commonwealth. Combined heat and power and demand response further contribute to the potential for both lower electricity consumption and reduced peak demand.

Figure 20. Summary of Energy Efficiency Resource Potential (44,000 GWh or 31% of Projected Electricity Use in 2025)



Impacts of Energy Efficiency and Demand Response

ACEEE recommends a suite of energy efficiency and demand response policies that would enable Virginia to tap into its energy efficiency potential. These recommendations include:

- Energy savings target (EERS)
- Demand response initiatives
- Lead by example in state and local government facilities
- Manufacturing initiative
- CHP supporting policies

Impacts on electricity use in Virginia over the study time period are shown in Figure 21. The combined effects of energy and demand response on overall summer peak demand are shown in Figure 22 and Table 20.

Figure 21. Estimated Reductions in Electricity Use in Virginia through Energy Efficiency — Medium Scenario

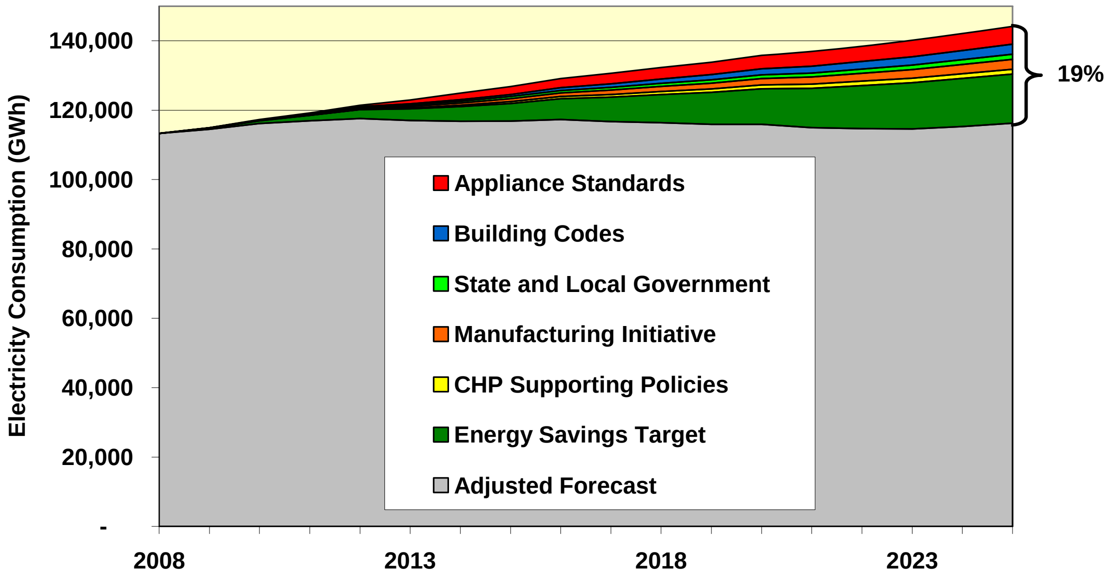
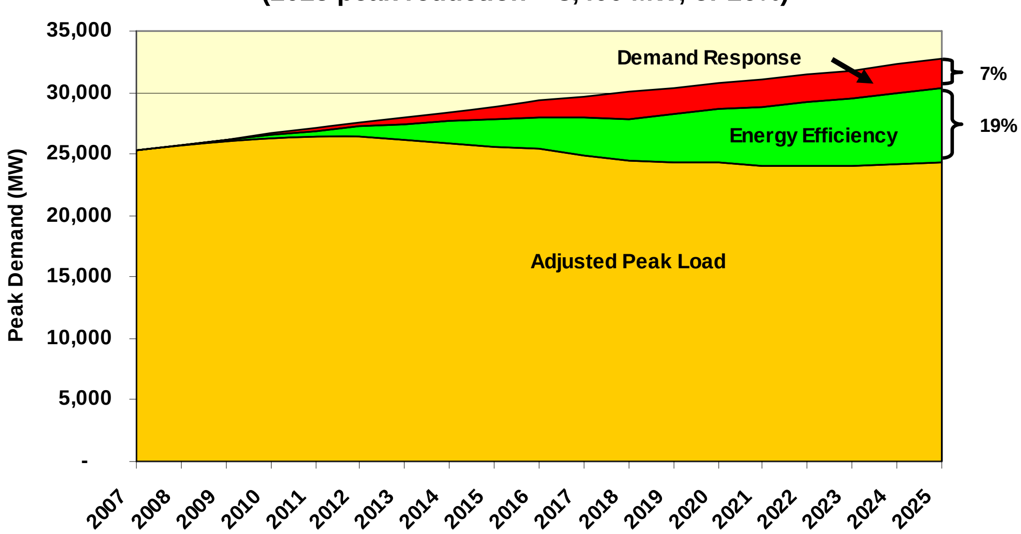


Table 20. Summary of Peak Demand Reduction Potential in Virginia

	2015	2025	% Reduction
Energy Efficiency Peak Reductions	2,169	6,048	18.5%
Demand Response Peak Reductions	1,038	2,345	7.2%
Total Peak Reductions	3,206	8,392	26%
% Reduction (total relative to forecast)	13%	26%	

Figure 22. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response — Medium Scenario (2025 peak reduction = 8,400 MW, or 26%)



Consumer Savings

The energy savings from these efficiency policies can cut the electricity bills of customers by a net $500 million in 2015. Net annual savings grow nearly five-fold to $2.2 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach $15 billion. To put this into context, an average household will save a net $5 on its monthly electricity bill by 2015 and $20 per month by 2025. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby helping to stabilize and contain increases in regional electricity prices for the future.

Macroeconomic Impacts

Investments in efficiency have the additional benefit of creating new, high-quality “green-collar” jobs in the Commonwealth and increasing both wages and GSP. Our analysis shows that energy efficiency investments can create nearly 10,000 new jobs in Virginia by 2025 (see Table 21), including well-paying trade and professional jobs needed to design and install energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to almost 100 new manufacturing plants relocating to Virginia, but without the public costs for infrastructure or the environmental impacts of new facilities.

Table 21. Economic Impact of Energy Efficiency Investments in Virginia

Macroeconomic Impacts	2015	2025
Jobs (Actual)	675	9,820
Wages (Million $2006)	63	583
GSP (Million $2006)	202	882

DISCUSSION AND RECOMMENDATIONS

The objectives of this ACEEE project and study are threefold:

- to engage varied stakeholders in Virginia who have a vested interest in energy issues on what is politically possible;
- to perform an analysis of the potential for increased energy efficiency in Virginia and to make and analyze specific policy recommendations tailored to the Commonwealth; and
- to inform the dialogue of Virginia stakeholders as energy efficiency policies and programs are considered utilizing the study’s findings and to provide ongoing follow-up (as resources allow) to interested parties.

Findings from the Stakeholder Process

The first aspect of this project—engaging stakeholders—reached out to as many different interested parties in Virginia as time and resources allowed. This outreach included state government, electric utilities, the utility commission, industrial and manufacturing consumers, and environmental organizations. In addition, a more limited communication was established with low income advocates and representatives from the state legislature though with less success than hoped due to lack of availability of representatives, since the legislature was not in session for the most part for the duration of this study. A key part of this effort was the sharing of a draft of this report with over fifty different stakeholder groups and individuals.

Several key issues of concern emerged from the comments received on a draft of the report. Common threads in these comments included:

- Cost-effectiveness of energy efficiency measures and avoided costs
- Data availability issues
- Reference case assumptions

Little consensus was found among the responders. In fact, the various comments reflected the highly polarized nature of the energy debate in the state. It was clear throughout the stakeholder process that there was unlikely to be much consensus on next steps for the state. It will take more dialog and additional analysis to make decisions and take action but at this point it is expected that this report will at least give some starting place for further deliberations, which was one goal of the study.

Cost Effectiveness and Avoided Costs

ACEEE's assessment of the overall potential for energy efficiency in Virginia took the perspective of an electric customer—i.e., if a consumer investment in efficiency costs less per kWh of electricity *saved* than a customer would have paid for that kWh *delivered,* then that investment is cost-effective. This approach is not what the utilities stakeholders use and, therefore, admittedly produces a different result from their current utility cost-effectiveness tests. There is no single definition of cost-effectiveness in the industry to evaluate the benefits of energy efficiency, and electric utilities use several different tests to calculate the costs and benefits of efficiency programs.[13] One commonly used method is the Total Resource Cost (TRC) test, which evaluates the net benefits of energy efficiency to the region as a whole. This test evaluates benefits as the avoided costs to utilities of not *generating* electricity. The Participant Cost Test, on the other hand, evaluates benefits as the costs that program participants avoid by not *purchasing* the saved electricity. Although our assessment of the efficiency resource potential takes the customer perspective, ACEEE used both the TRC and Participant tests in its assessment of the specific suite of energy efficiency policies, and both tests show positive, net benefits.

We also found a significant disagreement about what the future cost of electric resources would be in the state. While we developed approximate annual average utility avoided costs for this report, we strongly encourage that a more detailed assessment of avoided costs be undertaken as part of the Commonwealth's energy planning process. The development of a single, consensus avoided cost estimate would provide a common basis upon which evaluation of the best resource mix for the state could be based. Therefore, this issue might be an appropriate subject for an SCC proceeding.

Data Availability Issues and Reference Case

Difference in opinion about data and forecasts are in part due to the lack of consistent energy data and forecasts for the Commonwealth—as it is for most states. This lack of reliable data is one of the biggest challenges ACEEE faced in undertaking this and previous state studies. This problem results from a combination of factors. The movement in the 1990s toward utility restructuring in many states including Virginia not only resulted in the suspension of most energy efficiency utility programs, but also led to termination of many energy data collection and market surveying activities. This problem is not unique to states either. Budget cuts over the past decade have resulted in the termination of important data sources by federal agencies such as DOE's Energy Information Administration and the U.S. Census Bureau.

The absence of an entity to rationalize different data and forecasts creates uncertainty that distracts from the clear need to focus on the bigger energy policy issues facing Virginia—issues this report can hopefully inform in terms of future deliberations for those making critical policy decisions. Due to the absence of a consistent electricity forecast for Virginia, we derive a forecast of electricity consumption growth based on PJM's 2008 annual load forecast, using only its service territories in Virginia to derive weighted-average growth rates for Virginia. We then apply this overall forecast to actual 2007-

[13] See The Regulatory Assistance Project (www.raponline.org) for more information.

year electric sales data for Virginia (EIA 2007c). Using this methodology, and extending the forecast through 2025 to cover the study period of this analysis, total electricity consumption in the state is projected to grow in the reference case at an average annual rate of 1.4% between 2008 and 2025.

If Virginia is serious about realizing the benefits of energy efficiency resources, the state, regional market entities including PJM, and utilities must be focused and strategic about identifying data needs and following through on collection of these data resources. These groups should work collaboratively to develop and implement a coordinated plan for collecting this information in order to effectively design and evaluate the performance of efficiency programs now and in the future.

To accomplish this task, a state agency such as DMME or SCC, or some third party such as a university[14] or a consortium of utilities and other key interested parties should be designated as the energy data coordinator for the state. While individual utilities will likely resume the collection of some of this data to support their programs, it is important that the collection is comprehensive and consistent across the state. This data collection entity should consider developing data resources including the following:

- *A consensus statewide electricity and peak demand reference forecast* on which to base the current and future efficiency targets.
- *Appliance saturation surveys* (similar coordinated surveys conducted by each utility, or perhaps a single survey with each utility on the steering committee and the study designed to provide utility-specific breakdowns).
- *New construction baseline surveys* (e.g., a statewide survey with utility-specific information). These should include building size and key features suggestive of energy efficiency.
- *End-use load-shape studies* to help identify the contribution of each major sectoral end-use to peak electrical demand. Power costs are particularly high during peak demand periods, and understanding and reducing the major loads at times of peak demand can be very cost-effective.
- *Measurement and verification studies* using common methodologies and reporting formats to provide data on measure and program costs and savings.

By having a single entity with the responsibility and resources to collect and analyze energy data, the state will be able to verify that its policies are achieving their goals, and future analysts will have the necessary data to identify energy efficiency opportunities and design programs to realize these energy efficiency resources. While having good data and forecasts will not save energy by itself, it represents an important enabling infrastructure, and can remove a distraction that appears to be inhibiting efforts to advance the energy policy discussion.

Workforce

Virginia, like most if not all states, faces growing concerns about its energy workforce due in part to the aging of the incumbent energy workforce complicated by a lack of entry of younger workers over the past two decades. This workforce shortage impacts energy efficiency particularly, since as noted in the economic analysis, energy efficiency tends to be more labor intensive than are supply resources, requiring a trained workforce to identify and implement the efficiency resources whether they are industrial plant process optimization or residential HVAC tune-ups. The workforce issue represents a key infrastructure challenge that is becoming more widely recognized (NAPEE 2007), so the Commonwealth must address the need to build an adequate workforce to meet the demands of the market. This issue is moving to the forefront in many states seeking to expand energy efficiency, and requires a focused response by state leaders, particularly with universities and community colleges. Leading states like Texas, New York, and California are mobilizing their workforce training infrastructure to begin to develop the energy efficiency experts and technicians needed to meet future market demand. Fortunately, Maryland already has expertise on energy efficiency within the University of Maryland system, which needs to be nurtured and expanded across the state. Virginia

[14] For example. California has CALifornia Measurement Advisory Council (CALMAC). See www.calmac.org.

has already taken some initial steps in this regard as is discussed in our manufacturing initiative proposal. The state should consider forming an energy workforce coordinating council that can bring together the key players across the state so they can begin to prepare to meet the staffing needs that a clean energy future requires.

Recommended Next Steps

ACEEE offers this report to the Commonwealth to help inform its deliberations on energy and climate change policies. We have attempted to tailor our nationwide experiences to the specific needs and opportunities of the state, recognizing that what is implemented with respect to programs and policies should be a decision of the citizens through their elected officials.

In preparing this report, ACEEE has drawn upon its almost three decades of work on energy efficiency policies and programs. Our policy recommendations are based upon our assessment of "best practices." We intend this report as a roadmap for further development of energy efficiency policies. We have attempted in many places to identify resources that are available for further development, and stand prepared to assist the Commonwealth with additional information and referrals. Policymakers in the state need to decide what policies and program options they are committed to pursuing.

Role of Key Policymakers

In our recommendations, we have suggested who ACEEE sees as the best positioned to lead the implementation of our program and policy recommendations. In ACEEE prior research, we have documented that many of these policies and programs can be successfully implemented by a number of different entities, and the choice is up to the policymakers.

- ***The Governor***—The Governor plays a key role in this process. Governor Kaine has already assumed the role of leader in the deliberations of energy efficiency and climate change policy for the state. In fact his leadership was an important motivation to ACEEE in undertaking this study. The Governor has the potential to implement at least parts of a number of our suggestions, including the expansion of the state and local facilities initiative, the manufacturing initiative and the proposals for expanded public awareness and education. In part, the Governor's most important role may be to use his position to raise awareness among the policy community and the public as to the role of energy efficiency in utility and climate policy.
- ***Legislature***—The legislature has already played a key role in setting the Commonwealth on its current energy path, and will continue to play a pivotal role because of its ability to both fund and direct energy policy for the state. The legislature should consider such steps as adoption of state appliance and equipment efficiency standards; increasing the Commonwealth's energy savings target; and funding the state and local government, manufacturing and low-income initiatives through the budget process.
- ***State Corporation Commission***—The SCC has been among the key agencies involved with the implementation of utility energy efficiency programs. The commission plays the role of the representative of consumers across the state, insuring that they receive the energy benefits that could reduce their future energy costs while enhancing the economic stability of the state. The SCC should oversee implementation of programs to reach the current 10% savings target, and address the lack of data needed to help these programs succeed.
- ***State Agencies***—Various agencies would play roles implementing various provisions such as the expanded state and local facilities initiative. The agencies could also play important supporting roles in the education and outreach effort that would be critical in engaging the state's consumers with the information needed for them to make informed energy investment decisions.
- ***Local Governments***—Local government entities are uniquely positioned to implement several important suggestions including implementation of building codes and programs for local government facilities (as is discussed in Elliott and Eldridge 2007).

- ***State Educational System***—With workforce identified as a key need, the state educational system would play a critical role in ensuring that a trained workforce is developed to fill the jobs that an expanded investment in energy efficiency would create.

Program and Policy Implementation

For most of the policy and programs, ACEEE has made suggestions as to what entity should implement the policies and programs. In ACEEE's review of successful programs and policies, a number of different entities have successfully implemented the programs and polices in other states (York, Kushler and Witt 2008). Our suggestions for Virginia are based on our assessment of what programs and policies are currently being implemented by existing entities, and the ability to leverage these ongoing efforts. For example, the state DMME, VPMEP, and universities are already delivering services for the manufacturing community, so building on those existing efforts allows expanded services to be delivered sooner. Similarly, the utilities have current relationships with their commercial and residential customers, so adding energy efficiency programs to the existing delivery channel appears the quickest way to ramp up efficiency programs to these markets. The state could implement an independent energy efficiency program administrator model, such as Vermont has done with Efficiency Vermont.[15] However, the establishment of such an entity would require significant time to organize the entity and staff up to deliver the programs.

CONCLUSIONS

The Commonwealth of Virginia finds itself at a juncture in the road with respect to its energy future. The state can either continue to depend upon conventional energy resource technologies to meet its growing needs for electric power as it has for more than a century, or it can chose to slow—or even to reduce—future demand for electricity by investing in energy efficiency and demand response. As this assessment documents, there are plenty of cost-effective energy efficiency and demand response opportunities in the state. However, as this report also discusses, these opportunities will not be realized without changes in policies and programs in the state. The state ranked 38th out of the 50 states in ACEEE’s 2007 state energy efficiency scorecard in large part because there has been little attention to energy efficiency in the past (Eldridge et al. 2007). We suggest a wide array of energy efficiency and demand response policies and program that have proven successful in other states, and can meet 90% of the increase in the state's electricity needs over the next 18 years, and meet 20% of the increase in peak demand. These policies and programs are already proving themselves in other states, delivering efficiency resources and reducing consumer electric expenditures. **And**, these policy and programs can accomplish this at a lower cost than building new generation and transmission, while at the same time creating close to 10,000 new, high-quality "green collar" jobs in 2025.

These policy and programs suggestions should not be viewed as prescriptive, but as the starting point for a dialog among stakeholders on how to realize the efficiency resource that is available in the state on the demand side. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically plausible in the state. Clearly there are other policies and programs, some of which we suggest in our aggressive scenario, that could be implemented to realize even more of the available energy efficiency resource.

Nor do we suggest that these recommendations will meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource available in the immediate future and can make an important contribution in the longer term, the state will need additional resources to meet the remainder of the new load and replace older, dirtier power plants in the coming years. Energy efficiency can, however, buy time for a robust discussion about what other resource choices—both conventional and alternative—the state will make in the future.

[15] For more information, visit www.efficiencyvermont.com/pages/.

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Appendix Table of Contents

Appendix A - Reference Case

A.1. Projection of Electricity Consumption and Peak Demand

The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a "business as usual" scenario. When developing a reference case, it is preferable to use forecasts that are specific to the state or region and that are agreed upon by key stakeholders. Initially we used the State Corporation Commission's (SCC) forecast from 2005, however the forecast only projected through 2011 and only included data from Dominion Power, referred to in the forecast as Virginia Power and Electric Company (SCC 2005). Furthermore, the projections we estimated using the growth rate from SCC's forecast were not consistent with projections we derived from other sources. Therefore, it was in our interest to opt for the methodology below. We report the reference case assumptions over the 2008-2015 study period.

A.1.1. Electricity Forecast

Virginia is part of PJM, the regional transmission operator for the Mid-Atlantic and parts of the East Central Area. PJM projects electricity demand on an annual basis. We used their 2008 forecast, which projects demand through 2023, to estimate an electricity forecast for Virginia. PJM does not estimate electricity demand for specific states, but does look at specific geographic zones. For the AEP, APCo, Dominion, and DP&L zones, the four regions that fall within the state of Virginia, PJM projects electricity demand to grow at an average annual rate of 0.92%, 0.59%, 1.60%, and 1.56%, respectively, between 2008 and 2023 (PJM 2007). We derived a forecast specific to Virginia by estimating the portion of electricity demand in each geographic region that falls within Virginia, and prorated regional sales data by Virginia electricity sales data by utility (EIA 2006c).

We forecasted growth in electricity consumption by taking PJM's 2008 annual load forecast through 2022 and adjusting it specifically to those service territories in Virginia to derive a weighted-average growth rate for Virginia. We then applied this overall forecast to actual 2007-year electric sales data for Virginia from the March 2008 edition of the *Electric Power Monthly* (EIA 2008a) and we adjusted to sector-specific rates using *Annual Energy Outlook* sector growth rates for the South Atlantic (EIA 2007c). Using this methodology, and extending the forecast through 2025 to cover the study period of this analysis, total electricity consumption in the state is projected to grow in the reference case at an average annual rate of 1.4% between 2008 (the analysis base year) and 2025, and 1.2%, 2.0%, and 0.2% in the residential, commercial, and industrial sectors respectively. Actual electricity consumption in 2007 was 110,924 GWh (EIA 2007c), and in the reference case grows to 126,833 GWh by 2015 and 144,195 GWh by 2025.

A.1.2. Peak Demand Forecast

According to data from PJM's 2008 forecast, peak demand in the AEP, APCo, Dominion, and DP&L zones is projected to grow 1.0%, 0.8%, 1.6%, and 1.9% respectively. To ascertain Virginia-specific load growth for each utility we again estimated the portion of peak demand in each of the geographic regions that falls within Virginia and prorated regional sales data using Virginia electricity sales data by utility.

We derived an overall peak demand (MW) forecast for Virginia from the electricity forecast described above and assumed a 55% load factor, based on PJM load data for Dominion in 2007. Using this methodology, we estimated a 2008 peak demand of about 26,000 MW, rising to nearly 33,000 MW in 2025 and an average annual growth rate of 1.4%.

Table A-1 Retail Electricity Sales and Peak Demand Forecast

	2010	2015	2020	2025	Average Annual Growth Rate
Electricity (GWh)					
Residential	46,721	50,097	53,318	55,503	**1.27%**
Commercial	50,710	56,522	62,129	68,083	**2.09%**
Industrial	19,920	20,214	20,376	20,608	**1.08%**
Total	**117,351**	**126,833**	**135,823**	**144,195**	**1.60%**
Summer Peak Demand (MW)					
Total	**26,771**	**29,054**	**31,120**	**32,865**	**1.45%**

A.1.3. Population

Population estimates were needed for this analysis to determine per-capita sales data. We consulted Economy.com (2008) for data on population in the State of Virginia. According to this source, population in Virginia will grow at an average annual rate of about 0.8%.

Table A-2 Virginia Population Forecast

	2010	2015	2020	2025	Annual Growth Rate
Population Estimate	7,952,084	8,287,240	8,618,034	8,949,443	0.80%

A.1.4. Retail Electricity Prices

ACEEE also developed a possible scenario for retail electricity prices in the reference case. Readers should note the important caveat that ACEEE does not aim to predict what electricity prices in Virginia will be in either the short- or long-term. Rather, our goal is to suggest a possible scenario, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Virginia.

Shown in Table A-3 are 2007 electricity prices in Virginia (EIA 2007c) and our estimates of retail rates by customer class over the study time period. This price scenario is based on three key factors. First, we use the average generation cost of electricity in Virginia over the time period from the analysis done by Synapse Energy Economics, discussed in the next section of the Appendix. These costs range from 6.3 to 7.2 cents per kWh over the study time period (in 2006$). Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the Southeastern Electric Reliability Council (SERC) (EIA 2007c). According to AEO, transmission and distribution cost adders for SERC range from about 2 to 2.1 cents per kWh. Finally, we estimate expected near-term increases due to fuel adjustments by investor-owned utilities and expectations of rate caps expiring in December 2008. By 2010, we assume that retail prices reach the production cost levels as estimated by Synapse plus the SERC-average retail price adders for transmission and distribution.

Table A-3. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2006$)

	2007*	2010	2015	2020	2025	Average
Residential	8.5	10.1	10.0	10.1	10.5	10.0
Commercial	6.3	9.1	8.9	9.1	9.4	8.9
Industrial	4.9	6.8	6.8	6.9	7.2	6.8
Average	6.9	8.8	8.7	8.9	9.2	8.7

Note: These figures are in real, 2006-year dollars and therefore do not take into account inflation.
* Actual rates (EIA 2007c), converted to 2006$

A.2. Projection of supply prices and avoided costs

Synapse Energy Economics developed projections of supply prices and avoided costs used in this study. These estimated were developed based on key input assumptions that were developed as part of the stakeholder engagement process. Synapse then developed a simplified Electricity Planning and Costing Model to develop the projections. As noted in the main report, two sets of projections were developed for the reference and moderate policy cases.

A.2.1. Caveats

The projections of production costs and avoided costs presented in this memo are based upon a number of simplifying and conservative assumptions that the stakeholder group consider reasonable for the purpose of this high-level policy study. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. In addition, Synapse Energy Economics considers it unrealistic to rely upon projections that exclude the cost of compliance with anticipated CO_2 emission regulations.

A.2.2. Key Assumptions

This section describes the key inputs to the electricity model that Synapse Energy Economics has developed for this project (Synapse electricity cost model), the rationale for the proposed values and the sources of those values. The final inputs are based upon a set of draft inputs developed by Synapse[1] that ACEEE reviewed with key stakeholders in Virginia. The key substantive differences between these final input assumptions and the draft input assumptions are changes in the projected natural gas prices and carbon compliance costs. ACEEE decided to use a lower projection for natural gas prices and zero costs for carbon compliance. In addition, ACEEE provided a Reference Case load forecast. The values of these inputs are provided in Attachment A to this memo.

The memo also provides a description of the Electricity Cost Model that we use to estimate future production costs and avoided costs. That description is provided in Appendix B.

Changes from the August 15 version, Deliverable 1 b, are indicated in ***italics***.

A.2.3. Input Assumptions

The key inputs to the electricity model are presented under the following twelve categories:

- Basic Modeling assumptions
- Base year Sales and revenues
- Base year Load and resource Balance

[1] Deliverable 1 Input Assumptions for Electricity Cost Model, June 23, 2008.

- In-State Base Year Generation Resource Performance and Cost Data
- New Generation Resource Performance and Cost Data
- Fuel Types
- Annual Energy and Peak Load
- Capacity retirements
- Capacity additions
- Fuel prices
- Purchased Power Costs
- Carbon Emission Costs

Basic Modeling Assumptions:

- The base year is 2007. All monetary values are reported in constant 2006 year dollars unless noted otherwise.
- The study period begins in 2008 and ends in 2030, an analysis period of 23 years.
- The reporting period is 2009 through 2025, a total of 17 years.
- The financial parameters for costing resource additions are as follows:
- Inflation Rate. 2.50%. Rationale - the twenty year average (1987-2006) derived from the chained GDP deflator is 2.47%.
- Nominal Discount Rate. ***9.0%.*** This represents the value for a regulated utility such as Dominion with a mix of equity and bond financing. Based on a 50/50 equity/debt mix with ***11%*** for equity and 7% for debt. Used for levelization of capital expenditures. Actual rates for specific projects will vary depending on the nature of the project and the implementing entity.
- Real Discount Rate. 5.85%. Derived from the Nominal Discount Rate and the Inflation Rate.
- Income Tax Rate. Federal rate of 35% and VA state rate of 6%. ***Property tax rate of 0.5% per annum of the initial plant cost based on the posted property tax rates for VA counties and considering plant location in a rural area.***

A.2.4. Base Year Sales and Revenues

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Table 8 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (tables 5.4 and 5.5) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html). The historic data indicates that about 35% of Virginia's energy needs and 22% of the capacity needs are met from outside of the state.

A.2.5. Base Year Load and Resource Balance

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Tables 5, 8 and 10 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (tables 1.6, 4.6, 4.20, 4.12 and 4.13) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html).

A.2.6. In-State Base Year Generation Resource Performance and Cost Data

From the above EIA data, we have the generation, CO_2 emissions and fuel costs for each generating group. From that we can derive the average heat rate for each group and the fuel component of the generation costs. To that we add typical industry values for O&M. Also from that EIA data we have the historic capacity factors associated with resource group. Those historic patterns are used to set the basis for future performance.

A.2.7. New Generation Resource Performance and Cost Data

For new generation resources we have used the technology parameters from the AEO 2008 Assumptions document. For capital costs we have used our professional judgment based on a number of sources to reflect current cost expectations for new construction.

Fuel Types
We use the three basic fuel types as specified in the EIA documents (Coal, Petroleum and Natural Gas) with the addition of nuclear and biomass.

A.2.8. Annual Energy and Peak Load

For energy we have used the Reference Case customer sales forecast developed by ACEEE. We then apply a historic loss factor to arrive at the system energy load. To obtain the system peak load we have applied a historic system load factor to the above energy load. For VA we have used the load factor derived from the hourly loads at the PJM Dominion Hub in 2007.

Capacity Retirements
There is very little information about future plant retirements and a variety of unknown circumstances may either work in favor of or against individual plants. It is however likely that some older less efficient generation will be retired in the future. To reflect this we are representing modest gradual retirement of existing resources in the model inputs. But it is quite likely than many existing plants will be retrofitted and their lives extended.

Capacity Additions
In order to meet future load growth, new generation resources must be added to the existing generation mix.

The electricity model is not a capacity expansion model that optimizes capacity additions by choosing among a set of resource alternatives to develop a least cost expansion plan. Instead, we will add new resources “manually” to meet reserve needs. Our analysis will consider three sets of additions:

Planned Additions—Near-term proposed new additions or uprates to existing plants that are in development or advanced stages of permitting and have a high likelihood of reaching commercial operation;

RPS Additions—Renewable generators that are added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,

Generic Additions—New generic conventional resources that are added to meet the residual capacity need after adding planned and RPS additions.

Planned Additions
Description*:* Our near-term entry forecast is based on projects in development or advanced stages of permitting, trade press, environmental permit applications, and internal knowledge. The VEPCO FERC Form 1 filing of 2007 Q4 lists several near term NG CT units, a NG CC unit for 2011, a coal unit for 2012 and a possible new nuclear unit sometime in the next 20 years.
Data Sources*:* FERC filings, Virginia Energy Plan.

RPS Additions
In April 2007 the Virginia Department of Mines, Minerals and Energy (DSIRE) established a voluntary renewable energy portfolio goal starting at 4% (of 2007 levels) in 2010 and increasing to 12% in 2022. The mix is only loosely specified with wind and solar earning double credit. In checking the existing resources it appears that the 2010 goal is pretty much met by the resources currently in place. For new additions we assume that the larger majority will be wind with modest and increasing amounts of solar and biomass in the future.

The operating characteristics are based on AEO 2008 and Synapse estimates based on experience elsewhere in the US.

Generic Additions
In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will need to be added to the model. A range of generation technologies was initially considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, IGCC[2], and nuclear. As mentioned above the currently proposed resources in Virginia are Nat Gas Combustion Turbine (NGCT), Nat Gas Combined Cycle (NGCC) and Coal Steam. Therefore, the generic additions will be those types of units and nuclear units will not be included.

Generic additions are made based on meeting a system-wide reserve target including out-of –state resources of 15%. For the generic additions we use a mix of 45% conventional coal, 35% NGCC and 20% gas peakers.

A.2.9. Fuel Prices

We start with fuel prices reported for the base year of 2007. We used several sources to reflect current prices through mid 2008, and expectations for the future.

For natural gas we use NYMEX futures as of August 11, 2008 to scale natural gas prices out for the next twelve years. After that point we apply the relative price trends from the AEO 2008 modeling. (This is a change from our initial forecast, which was based on NYMEX futures as of mid-June. because of the dramatic change in futures over that two month period.)

We set petroleum prices at a historically determined multiple of natural gas prices. For coal we use the reported base year cost scaled by the relative year to year changes from AEO 2008.

A.2.10. Purchased Power Costs

Historic purchased power costs were obtained from the VEPCO FERC Form 1 filing for 2007 (Q4). Future purchased power costs are assumed to increase at the same rate as in-state power production costs.

A.2.11. Carbon Emission Costs

Carbon compliance costs were set at zero as requested by the ACEEE and the stakeholder group. Synapse Energy Economics considers it unrealistic to rely upon projections that exclude the cost of compliance with anticipated CO_2 emission regulations.

A.3.Electricity Planning and Costing Model

This model was developed by Synapse for ACEEE's clean energy state studies.

[2] Integrated gasification combined cycle

A.3.1. Background

ACEEE has initiated a series of state-specific "Clean Energy" potential studies through which it will work with key stakeholders in order to build a common understanding of, and consensus on, the role that clean energy resources, i.e., energy efficiency and demand response, can play in meeting the future electricity end-use requirements in each state, the economic benefits of treating those resources as the "first fuel" for meeting future requirements and the policies for maximizing reliance upon those resources. The time horizon for the studies is through 2025.

In each of those studies ACEEE will evaluate the cost effectiveness of reductions from energy efficiency and demand response, and will also demonstrate the benefits of those reductions to all consumers in the state by estimating retail prices in the long-term under a clean energy Policy Case.

ACEEE retained Synapse to provide three deliverables to support these studies

- projections of long-term wholesale electricity supply prices under a reference, or business-as-usual case;
- credible, consistent, "high-level" estimates of avoided electric energy ($/kWh) and capacity costs ($/kW-year); and
- projections of long-term electricity supply prices under a clean energy policy case.

In light of time and budget constraints, and the policy nature of these studies, ACEEE requested that Synapse develop and apply an electricity planning and costing model that would produce accurate "high-level" estimates of each of these deliverables in a well-documented, transparent manner.

In order to satisfy the ACEEE request, Synapse had to develop an electricity planning and costing model that would be:

- applicable to planning and costing from a state perspective, although most electric utility operations cross state boundaries;
- applicable from state to state, although some states are part of deregulated multi-state markets while others operate under traditional utility regulation;
- applicable using public data;
- inexpensive to setup and run; and
- relatively transparent.

Synapse has developed an EXCEL based planning and costing model with these characteristics.

A.3.2. Methodology

The model begins with an analysis of actual physical and cost data for a base year, develops a plan for meeting projected physical requirements in each future year of the study period and then calculates the incremental wholesale electricity costs associated with that plan. (Incremental to electricity supply costs being recovered in current retail rates).

A.3.3. Base Year Data

The actual data for the base year, and prior years, provides our starting point. That dataset contains historical data in the following categories:

1. Recent year summary statistics.
2. Listing of the ten largest plants in the state.
3. Top five providers of retail electricity
4. Electric capability by primary energy source.

5. Generation by primary energy source.
6. Fuel prices and quality.
7. Emissions.
8. Retail sales and revenues by customer class.
9. Retail sales by various provider types.
10. Supply and distribution of electricity.

This data enables us to characterize the electric supply system and its costs for a given state. For example the capacity, generation and capacity factor, average heat rate and fuel costs for different classes of resources. We can also calculate the retail margin from this data, i.e. the margin between average retail rates and variable production costs. The retail margin reflects the transmission and distribution costs being recovered in retail rates plus the fixed generation costs being recovered in those rates. This data is a very broad brush since the resources are grouped by fuel type and their operation is not characterized in great detail.

A.3.4. Future Years

We begin with the forecast of annual demand and energy in each future year provided by the ACEEE stakeholder group.

Next we develop a physical plan to meet the load in each of those future years. This is done in the model via the following steps:

1. Derive annual capacity and generation requirements from forecast of retail annual demand and energy, and reserve margins,
2. Determine the relative quantities of annual capacity and generation to be provided by in-state and out-state resources based on the current mix of in-state and out-of state resources,
3. Estimate resource retirements. It is quite difficult to predict the timing of actual plant retirements, but it is reasonable to assume that some older facilities will be retired during the study period. We assume gradual retirement of existing resources over time based on typical operating lifetimes. This is explicitly specified in the input data section and can easily be modified if more specific data becomes available.
4. Estimate the capacity, timing and timing of new generation additions, in-state and out of state. Our model is not a capacity expansion model and therefore does not make capacity additions “automatically”. Instead, after we include “planned” capacity additions, we add enough “generic” capacity additions to maintain the reserve margin. Our generic additions are a mix of peaking, intermediate and baseload units that maintains the historical mix of those categories in the state. This approach is transparent as the additions are explicitly specified in the input data section.
5. Calculate the quantity of annual generation from each category of capacity, existing and new, in-state and out of state. The estimated quantity of generation from each category of capacity is derived from the operating capacity factors. These are generally based upon economic dispatch, i.e. dispatch from each category in order of increasing variable production costs

A.3.5. Calculate Production Costs

The model calculates the production costs for the particular plan via the following steps:

1. Calculate total cost of generation from existing in-state resources, purchases from out-of-state resources, and new in-state resources. This is a projection of total unit production costs, i.e. levelized capital costs plus current operating costs, for generation from each of the three major categories of resources: existing generation, new generation and imports. The production costs of existing in-state generation includes variable operating costs plus fixed

costs. The cost of generation from these resources decline over time as existing coal, oil and gas plants are retired, while the existing nuclear plants with low operating costs continue operation. The cost of power imported from out-of-state is indexed to the generation-weighted average cost of generation from in state resources, i.e., existing and new.

2. Apply the levelized capital cost for new capacity additions to calculate the full cost of energy from these resources.
3. Apply retail margin to estimate average retail price.

A.3.6. Calculate Avoided Costs

Finally, the model estimates the avoided costs via the following steps:

1. Calculate the total costs of the resources that would be avoided. These avoided resources and their avoided costs include avoided dispatch from existing in-state resources, i.e. variable operating costs, and avoided construction and dispatch of new in-state resources, i.e. capital costs and variable operating costs. In the first five years the avoided costs are a mix of avoided dispatch of existing resources and avoided total cost of new resources that would otherwise come-on-line during that period. The percentage of new resources included in that mix is phased-in, starting at 0% in year 1 and rising to 100% in year 5. After year 5 the avoided costs in each year equal the average total costs of new resources in that year. This calculation assumes that the capital costs of new resources are avoidable either through avoiding their actual construction or through recovery from revenues from off-system sales.
2. Calculate avoided capacity cost based upon cost of a new gas combustion turbine "peaker" unit. Basing avoided capacity cost on the capital cost of a new peaker is a commonly accepted method. This is expressed in both a capacity and an energy basis.
3. Calculate energy-only avoided cost. Taking the costs in step 9 above which include both operating and capital costs and subtracting the capacity costs from step 10 gives the equivalent energy-only avoided cost

A.4.Reference Case Electricity Supply Prices and Avoided Costs

This section presents Synape's projections of *Reference Case* electricity supply prices and avoided costs for Virginia. The projections are outputs from the electricity costing model that Synapse Energy Economics has developed for this project. The inputs to the model, and the structure of the model, are described above.

A.4.1. Reference Case Electricity Supply Prices

The reference case load forecast, supply forecast, and supply prices are presented in Table A-4. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.4.2. Avoided Electricity Costs

The avoided costs are presented in Table A-5. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh.

Table A-4 Reference Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.

CASE: **VA Reference Case - 9/5/08**

Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	114,975	117,351	119,245	121,460	122,947	124,957	126,833	129,143	130,657	132,322	133,825	135,823	136,945	138,563	140,150	142,157	144,195
Retail Demand	MW	23,864	24,357	24,750	25,210	25,518	25,936	26,325	26,804	27,119	27,464	27,776	28,191	28,424	28,759	29,089	29,505	29,928
Supply Forecast																		
Capacity Requirement	MW	30,026	30,646	31,141	31,719	32,107	32,633	33,122	33,726	34,121	34,556	34,948	35,470	35,763	36,186	36,600	37,124	37,656
Capacity Sources																		
In-State Capacity	MW	22,918	22,689	23,180	23,655	23,745	23,788	24,060	24,175	24,546	24,218	24,460	24,367	24,001	23,636	23,585	23,664	23,807
Out-of-State Capacity	MW	7,108	7,957	7,961	8,064	8,362	8,845	9,063	9,550	9,575	10,338	10,489	11,103	11,762	12,550	13,015	13,460	13,849
Total Capacity Provided	MW	30,026	30,646	31,141	31,719	32,107	32,633	33,122	33,726	34,121	34,556	34,948	35,470	35,763	36,186	36,600	37,124	37,656
Energy Requirement	GWh	125,795	128,394	130,467	132,890	134,516	136,716	138,768	141,296	142,953	144,774	146,419	148,605	149,832	151,602	153,338	155,535	157,764
Energy Sources																		
In-State Generation	GWh	79,225	78,282	81,280	84,698	87,258	88,791	91,577	93,509	96,976	96,615	99,379	107,405	106,841	106,277	107,434	109,308	111,529
Out-of-State Generation	GWh	46,570	50,112	49,187	48,191	47,258	47,925	47,191	47,787	45,976	48,159	47,039	41,200	42,991	45,325	45,904	46,226	46,236
Total Energy Provided	GWh	125,795	128,394	130,467	132,890	134,516	136,716	138,768	141,296	142,953	144,774	146,419	148,605	149,832	151,602	153,338	155,535	157,764
Supply Price Forecast																		
Average Production Cost	¢/kWh	6.25	6.29	6.35	6.36	6.35	6.37	6.42	6.47	6.53	6.57	6.62	6.80	6.83	6.92	6.99	7.07	7.15

Table A-5 Reference Case Avoided Costs

All costs in constant 2006 dollars.

CASE: **VA Reference Case - 9/5/08**

Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.50	6.17	6.75	7.27	7.61	8.07	8.00	7.94	7.91	7.92	7.90	8.11	8.11	8.16	8.17	8.19	8.22
Avoided Capacity Cost	$/kW-yr	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	4.06	4.74	5.32	5.84	6.18	6.64	6.56	6.51	6.48	6.49	6.47	6.68	6.68	6.73	6.74	6.76	6.78

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

A.5.Policy Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of *Policy Case* electricity supply prices and avoided costs for Virginia. The projections are outputs from the electricity costing model that Synapse has developed for this project as discussed above. ACEEE provided the Policy Case Load Forecast.

A.5.1. Policy Case Electricity Supply Prices

The Policy Case load forecast, supply forecast, and supply prices are presented in Table A-6. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.5.2. Avoided Electricity Costs

The avoided costs are presented in Table A-7. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh.

Table A-6. Policy Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.

CASE:	**VA Policy Case - 9/5/08**																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	114,567	116,250	117,128	117,823	117,262	117,078	117,190	117,700	117,176	116,905	116,497	116,502	115,614	115,351	115,356	116,076	117,113
Retail Demand	MW	23,782	24,138	24,330	24,488	24,396	24,383	24,427	24,550	24,468	24,432	24,367	24,390	24,226	24,192	24,208	24,369	24,593
Supply Forecast																		
Capacity Requirement	MW	29,923	30,371	30,612	30,811	30,695	30,679	30,735	30,889	30,786	30,741	30,660	30,687	30,482	30,439	30,459	30,662	30,944
Capacity Sources																		
In-State Capacity	MW	22,918	22,589	22,780	22,955	23,045	22,636	22,349	22,236	22,195	21,830	21,464	21,098	20,733	20,367	20,001	19,636	19,606
Out-of-State Capacity	MW	7,005	7,781	7,833	7,856	7,650	8,044	8,386	8,654	8,591	8,911	9,196	9,589	9,750	10,072	10,458	11,026	11,338
Total Capacity Provided	MW	29,923	30,371	30,612	30,811	30,695	30,679	30,735	30,889	30,786	30,741	30,660	30,687	30,482	30,439	30,459	30,662	30,944
Energy Requirement	GWh	125,348	127,190	128,151	128,911	128,297	128,095	128,219	128,776	128,202	127,906	127,459	127,466	126,494	126,207	126,211	126,999	128,134
Energy Sources																		
In-State Generation	GWh	79,225	78,195	80,930	84,085	86,645	85,701	85,430	86,108	87,326	86,761	86,197	85,633	85,068	84,504	83,940	83,375	84,651
Out-of-State Generation	GWh	46,123	48,995	47,221	44,826	41,652	42,395	42,789	42,669	40,877	41,145	41,263	41,833	41,426	41,703	42,272	43,624	43,483
Total Energy Provided	GWh	125,348	127,190	128,151	128,911	128,297	128,095	128,219	128,776	128,202	127,906	127,459	127,466	126,494	126,207	126,211	126,999	128,134
Supply Price Forecast																		
Average Production Cost	6.26	6.24	6.26	6.27	6.23	6.19	6.15	6.16	6.18	6.21	6.22	6.24	6.28	6.29	6.35	6.40	6.47	6.57

Table A-7 Policy Case Avoided Costs

All costs in constant 2006 dollars.

CASE:	**VA Policy Case - 9/5/08**																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.50	6.17	6.75	7.07	7.33	7.73	7.74	7.73	7.76	7.80	7.84	7.89	7.92	7.99	8.05	8.11	8.16
Avoided Capacity Cost	$/kW-yr	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06	69.06
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	4.06	4.74	5.32	5.64	5.90	6.30	6.30	6.30	6.33	6.37	6.41	6.46	6.49	6.56	6.62	6.68	6.73

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

Appendix B - Energy Efficiency Policy Scenarios

B.1. Electricity Savings, Peak Demand Reductions, and Costs from Policy Scenarios

B.1.1. Low-Case Policy Scenario

Table B-1. Electricity Savings in Low-Case Policy Scenario (GWh)

	Policy/Program	**2010**	**2015**	**2020**	**2025**	% Savings in 2025 (relative to forecast)
1	Energy Efficiency Resource Standard	857	4,791	8,980	10,656	7%
2	Building Energy Codes	-	379	880	1,354	1%
3	Appliance Efficiency Standards (Federal)	107	2,147	3,624	4,741	3%
	Total Savings	964	7,317	13,484	16,750	12%
	Adjusted Forecast	116,387	119,516	122,340	127,445	
	% Savings (cumulative)	1%	6%	10%	12%	
Notes						
1	Assumes savings of 10% by 2022, relative to 2006 consumption. Annual savings start at 0.25% in Yr 1, 0.5% in Yr 2, 0.5% in Yr3, relative to prior-year sales, and interpolate to reach 10% by 2022. For technology costs by sector, we assume first-year investment costs of $0.34, $0.17, and $0.29 per kWh for the residential, commercial, and industrial sectors, respectively, at the time of measure adoption or implementation.					
2	Assumes the IECC 2009 is adopted, which goes into effect 2011. We estimate that this code will be a 15% energy savings improvement beyond IECC 2006 requirements. Savings apply only to end-uses covered under building codes, which are HVAC, lighting, and water heating end-uses. We assume enforcement of the codes starts at 70% compliance in the first year, 80% in second year, and 90% in subsequent years. Based on the buildings analysis, we assume a $0.62 per kWh investment cost at the time of construction for new residential buildings that comply with the new code and $0.20 per kWh for new commercial buildings. We assume $1.5 million dollars per year to implement and enforce codes, based on recommendations in New York (NY DPS 2007). This is similar to estimates in VA that new program costs run 2-3% of building costs.					
3	Appliance and equipment efficiency standards were adopted at the federal level in the 2007 energy bill, which also directed DOE to set standards for additional products in the coming years. This Scenario assumes savings from these standards, which are not taken into account in the reference case load forecast. Savings and cost assumptions are from a forthcoming ACEEE and ASAP standards analysis.					
	Savings by Sector					
	Residential	352	2,929	5,371	6,725	5%
	Commercial	425	3,129	5,809	7,231	5%
	Industrial	186	1,259	2,303	2,795	2%
	Total Savings	964	7,317	13,484	16,750	12%

Table B-2. Summer Peak Demand Reductions in Low-Case Scenario (MW)

	2010	**2015**	**2020**	**2025**	
Residential	77	644	1,182	1,479	5%
Commercial	102	751	1,394	1,735	5%
Industrial	26	176	322	391	1%
Total Savings	206	1,572	2,898	3,606	11%
% Reduction (relative to forecast)	1%	5%	9%	11%	

Table B-3. Total Resource Costs* in Low-Case Scenario (Million 2006$)

Policy/Program	**2010**	**2015**	**2020**	**2025**
Energy Efficiency Resource Standard	$160	$234	$234	$0
Building Energy Codes	$0	$43	$42	$36
Appliance Efficiency Standards (Federal)	$16	$154	$189	$189
Total Costs	$176	$431	$465	$225

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

B.1.2. Medium-Case Policy Scenario

Table B-4. Electricity Savings in Medium-Case Policy Scenario (GWh)

	Policy/Program	**2010**	**2015**	**2020**	**2025**	
1	Energy Efficiency Resource Standard	**857**	**6,477**	**13,216**	**18,437**	13%
2	*Clean Distributed Generation Policies*	*44*	*504*	*1,075*	*1,394*	*1%*
3	*State Manufacturer Initiative*	*25*	*850*	*1,864*	*2,883*	*2%*
4	State Facilities	58	205	351	497	0.3%
5	Local Government Facilities	117	409	702	994	1%
6	Building Energy Codes	-	595	1,720	2,821	2%
7a	Appliance Efficiency Standards (Federal)	107	2,147	3,624	4,741	3%
7b	Appliance Efficiency Standards (State)	5	125	279	425	0%
	Total Savings	1,144	9,957	19,892	27,914	19%
	Adjusted Forecast	116,207	116,876	115,932	116,281	
	% Savings (Total relative to forecast)	1%	8%	15%	19%	
	Notes					
1	Assumes savings of 15% by 2022, relative to 2006 consumption Annual savings start at 0.25% in Yr 1, 0.5% in Yr 2, 0.75% in Yr 3, 1% in Yrs 4 - 8, and about 1.1% in Yrs 9 - 17 to reach 15% by 2022 and 19% by 2025. Industrial sector savings and costs are those from CHP policies and the Manufacturing Initiative (see below). Residential and commercial sector cost assumptions are the same as Scenario One.					
2	This scenario assume that the effective cost of installing CHP is reduced by $500 per kW as a result of reduced project uncertainty and delays as a result of removal of market barriers as described in the text.					
3	This scenario assumes that the number of industrial assessments ramps up from 50 to 200 in first three years, that each assessment identifies 20% electricity savings, and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.29/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.					
4	This Scenario assumes that Virginia expands its Energy Savings Performance Contract (ESPC) program to complete projects in 50% of state facilities by 2025 and that projects achieve an average energy savings of 20%. Costs assume the average investment cost per kWh from the commercial sector analysis ($0.17/kWh).					
5	Assumes the same participation rate, savings, and costs as state facilities.					
6	Assumes the same as Scenario One, plus adoption of the IECC 2102 which go into effect in 2015. We estimate that the IECC 2012 achieves 30% energy savings improvement beyond IECC 2006 requirements. Compliance assumptions are the same as Scenario One, and apply at adoption of each new code. Cost assumptions are the same as Scenario One.					
7a	Same as Scenario One.					
7b	In addition to federal efficiency standards, this scenario assumes that Virginia adopts state-level standards for six products: DVD players, compact audio equipment, hot food holding cabinets, portable electric spas, water dispensers, and furnace fans.					
	Savings by Sector					
	Residential	382	3,562	7,078	9,787	7%
	Commercial	708	5,070	10,080	14,121	10%
	Industrial	54	1,325	2,733	4,006	3%
	Total Savings	1,144	9,957	19,892	27,914	19%

Table B-5. Summer Peak Demand Reductions in Medium-Case Scenario (MW)

	2010	2015	2020	2025	
Residential	84	784	1,557	2,153	7%
Commercial	169	1,194	2,368	3,318	10%
Industrial	9	191	394	577	2%
Total Savings	261	2,169	4,319	6,048	18%
% Reduction (relative to forecast)	1%	8%	14%	18%	

Table B-6. Total Resource Costs* in Medium-Case Scenario (Million 2006$)

Policy/Program	2010	2015	2020	2025
Energy Efficiency Resource Standard	$156	$331	$378	$382
Clean Distributed Generation Policies	*$8*	*$36*	*$24*	*$12*
State Manufacturer Initiative	*$8*	*$61*	*$62*	*$62*
State Facilities	$5	$5	$5	$5
Local Government Facilities	$10	$10	$10	$10
Building Energy Codes	$0	$69	$86	$75
Appliance Efficiency Standards (Federal and State)	$16	$161	$196	$196
Total Costs	$187	$575	$676	$668

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

Table B-7. Electricity Savings in High-Case Policy Scenario (GWh)

		2010	2015	2020	2025	
1	Energy Efficiency Resource Standard	857	7,948	16,875	25,748	18%
2	*Clean Distributed Generation Policies*	*202*	*1,572*	*3,079*	*3,829*	3%
3	*State Manufacturer Initiative*	*25*	*925*	*2,193*	*3,467*	2%
4	State Facilities	88	307	526	746	1%
5	Local Government Facilities	175	614	1,052	1,491	1%
6	Building Energy Codes	-	424	1,408	2,884	2%
7a	Appliance Efficiency Standards (Federal)	107	2,147	3,624	4,741	3%
7b	Appliance Efficiency Standards (State)	5	125	279	425	0.3%
8	Energy Efficiency RD&D Initiative	-	29	294	3,083	2%
	Total Savings	1,232	11,593	24,060	39,117	27%
	Adjusted Forecast	**116,119**	**115,240**	**111,764**	**105,078**	
	% Savings (cumulative)	**1%**	**9%**	**18%**	**27%**	
1	Assumes 19% savings by 2022, relative to 2006 consumption. Annual savings, relative to prior-year sales, are 0.25% in Yr 1, 0.5% in Yr 2, 0.75% in Yr3, 1% in yr 4, 1.25% in yr 5, and 1.5% in yr 6 and remaining years to reach 19% cumulative by 2022. Industrial sector savings and costs are those from CHP policies and the Manufacturing Initiative (see below). Residential and commercial sector cost assumptions are the same as Scenario One.					
2	This scenario assumes that in addition to removal of barriers, CHP receives either directly or indirectly incentives that have the effect of reducing the installed cost of CHP capacity by $100 per kW.					
3	This scenario assumes that the number of assessments ramps up from 50 to 200 in first three years and then to 250 in year 5, that each assessment identifies 20% electricity savings and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.29/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.					
4	This Scenario assumes that Virginia expands its Energy Savings Performance Contract (ESPC) program to complete projects in 75% of state facilities by 2025 and that projects achieve an average energy savings of 20%. Costs assume the average investment cost per kWh from the commercial sector analysis.					
5	Assumes the same participation rate, savings, and costs as state facilities.					

		2010	2015	2020	2025	
6	Same as Scenario Two, plus adoption of a new code in 2018, effective 2021, that achieves 50% savings beyond the IECC 2006. Compliance assumptions are the same as Scenario One, and apply at adoption of each new code. Cost assumptions are the same as Scenario One, assuming that costs for new construction at this level of savings comes down to current costs of 15% and 30% beyond-code buildings.					
7a	Same as Scenario One.					
7b	Same as Scenario Two.					
8	This scenario assumes that Virginia invests in an RD&D effort specific to energy efficiency.					
	Residential	368	3,997	8,313	13,666	9%
	Commercial	774	5,948	12,196	19,906	14%
	Industrial	89	1,648	3,550	5,545	4%
	Total Savings	1,232	11,593	24,060	39,117	27%

Table B-8. Total Resource Costs* in High-Case Scenario (Million 2006$)

Policy/Program	**2010**	**2015**	**2020**	**2025**
Energy Efficiency Resource Standard	$156	$477	$484	$481
Clean Distributed Generation Policies	*$24*	*$82*	*$50*	*$22*
State Manufacturer Initiative	*$8*	*$76*	*$77*	*$78*
State Facilities	$8	$8	$8	$8
Local Government Facilities	$15	$15	$15	$15
Building Energy Codes	$0	$66	$83	$118
Appliance Efficiency Standards (Federal and State)	$16	$161	$196	$196
Energy Efficiency RD&D Initiative	$7	$9	$36	$305
Total Costs	$202	$736	$820	$1,123

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

B.2.Carbon Dioxide Emissions Reductions

To estimate annual regional emissions reductions, we first took data on projected electricity generation and carbon dioxide emissions over the 2007-2025 period for the South-Eastern Reliability Council (SERC) region as reported by the *Annual Energy Outlook* (EIA 2007c). We then calculated an *output emission rate*, defined as the ratio of emissions (lbs) to electricity generation (MWh). Using data from the Emissions and Generation Resource Integrated Database (eGRID) on subregional emission rates and converting to standard tons (EPA 2007), we calculated a *net marginal emissions factor* (ton/MWh), which is our *output emission rate* multiplied by the ratio of marginal to average emission rates. We then took our *emissions factor* and multiplied by Virginia's estimated electricity savings (GWh) from Policy Scenario Two in order to determine the regional *carbon dioxide emissions savings* for the 18-year period.

Appendix C - Energy Efficiency Resource Assessment

C.1.Residential Buildings

C.1.1. Overview of Approach

We analyzed thirty-four electricity efficiency measures for existing residential buildings, which are grouped by end-use (HVAC, water heating, refrigeration, appliances, lighting, furnace fans, and plug loads) and three measures for new residential buildings (see Table A.1). For each measure, we estimated average measure lifetime, electricity savings (kWh) and costs per home upon replacement of the product or retrofitting of the measure. For a replacement-on-burnout measure,[3] the cost is the incremental cost of the efficient technology compared to the baseline technology. For retrofit measures, where existing equipment is not being replaced, such as improved insulation and infiltration reduction, the cost is the full installation cost of the measure. For measures modeled as replacement-on-burnout, the baseline is set according to the current market for that product, so the baseline efficiency is the minimum efficiency standard of that product. For measures modeled as retrofit, the baseline efficiency is that of estimated energy use in existing Virginia homes.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than 10.7 cents/kWh, the current average residential cost of electricity in Virginia (EIA 2008b). Estimated levelized costs for each efficiency measure, which assume a discount rate of 5%, are shown in Table C.1. Equation one shows the calculation for cost of conserved energy.

Equation 1. *CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))*

[3] In a replacement-on-burnout scenario, a consumer purchases the more efficient product at the time of replacement of that product.

Table C.1 Residential Energy Efficiency Measure Characterizations

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Existing Building					**2025**		**2025**	**2025**	
Seal Ductwork	HVAC (load)	639	$ 0.09	yes	100%	50%	100%	10%	1039
Insulate Ductwork, R-8	HVAC (load)	639	$ 0.03	yes	100%	50%	90%	9%	937
Infiltration reduction	HVAC (load)	799	$ 0.01	yes	100%	40%	80%	8%	844
Insulation, ceiling, R-11 to R-38	HVAC (load)	703	$ 0.02	yes	100%	28%	70%	4%	455
Insulation, ceiling, R-19 to R-38	HVAC (load)	314	$ 0.05	yes	100%	41%	70%	3%	291
Blow-in wall insulation	HVAC (load)	1198	$ 0.03	yes	100%	16%	61%	4%	379
Estar Window, from single pane	HVAC (load)	2301	$ 0.01	yes	57%	24%	55%	5%	544
Estar Window, from double pane	HVAC (load)	575	$ 0.05	yes	57%	50%	55%	3%	289
Cool Roof shingles	HVAC (load)	413	$ 0.03	yes	85%	77%	40%	3%	355
HVAC Load Reducing Measures								**48%**	
Central HP (heating cycle); HSPF 9	HVAC (equipment)	606	$ 0.09	yes	94%	13%	52%	1%	128
GSHP w/ desuperheater (14 EER)	HVAC (equipment)	2684	$ 0.08	yes	94%	3%	52%	1%	114
Central AC (cooling cycle) SEER 15	HVAC (equipment)	269	$ 0.03	yes	94%	53%	52%	2%	224
ENERGY STAR Dehumidifier	HVAC (equipment)	213	$ 0.08	yes	100%	5%	52%	0%	19
Energy Star Room A/C (10.8 EER)	HVAC (equipment)	112	$ 0.05	yes	100%	32%	52%	1%	59
Ceiling Fan (including light kit)	HVAC (equipment)	313	$ 0.08	yes	100%	50%	52%	2%	263
HVAC Equipment Measures								**8%**	
TOTAL HVAC								**56%**	**5940**
High-efficiency showerheads	Water Heating	250	$ 0.01	yes	100%	27%	100%	6%	219
Faucet aerators	Water Heating	48	$ 0.02	yes	100%	29%	100%	1%	46
Water heater pipe insulation	Water Heating	65	$ 0.05	yes	100%	39%	100%	2%	83
H-axis clothes washer (2.0 MEF) (water heating)	Water Heating	232	$ 0.08	yes	100%	24%	100%	5%	180
Dishwasher (Electric WH; 0.68 EF) (water heating)	Water Heating	43	$ 0.06	yes	100%	23%	100%	1%	32
GSHP w/ desuperheater (14 EER)	Water Heating	627	$ 0.14	no	94%	27%	84%	12%	432

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Efficient electric water heater (0.93 EF)	Water Heating	81	$ 0.09	yes	100%	29%	84%	2%	63
Heat pump water heater (COP = 2.0)	Water Heating	1505	$ 0.06	yes	100%	16%	84%	18%	639
Water Heating Savings								**49%**	**1695**
Refrigerator (20%)	Refrigeration	114	$ 0.05	yes	89%	81%	100%	6%	330
Refrigerator (25%)	Refrigeration	29	$ 0.10	yes	89%	115%	100%	2%	117
Refrigeration Savings								**8%**	**447**
CFL, Advanced Incandescent Replacements	Lighting	1005	$ (0.00)	yes	100%	90%	100%	43%	2939
Lighting Savings								**43%**	**2939**
H-axis clothes washer (2.0 MEF)	Appliances	26	$ 0.08	yes	100%	53%	100%	2%	55
Dishwasher (Electric WH; 0.68 EF)	Appliances	11	$ 0.08	yes	100%	47%	100%	1%	21
Appliances Savings								**2%**	**76**
Efficient Furnace Fan (Heating Season)	Furnace Fans	322	$ 0.04	yes	94%	55%	100%	26%	666
Efficient Furnace Fan (Cooling Season)	Furnace Fans	164	$ 0.04	yes	94%	55%	100%	13%	339
Furnace Fan Savings								**39%**	**1005**
Active Mode Standard for TV	Plug Loads	183	$ 0.03	yes	100%	74%	100%	4%	133
Set-Top Box Power Reduction	Plug Loads	120	$ 0.03	yes	100%	58%	100%	2%	69
1-watt standby power	Plug Loads	264	$ 0.02	yes	100%	66%	100%	5%	698
Total Plug Load Savings								**11%**	**900**
In-home energy feedback monitor	All	1386	$ 0.02	yes	100%	67%	10%	1%	376
New Construction Building Measures									
New home 15% better than code (Energy Star home)	New Construction	962	$ 0.05	yes	100%	17%	100%	1%	67
New home 30% better than code (Proposed Building Code)	New Construction	1924	$ 0.05	yes	100%	35%	100%	5%	274
New home 50% better than code (Tax-credit-eligible)	New Construction	3207	$ 0.06	yes	100%	47%	100%	11%	608
New Homes Subtotal									**949**

C.1.2. Existing Buildings

To estimate the efficiency resource potential in existing homes in Virginia by 2025, we first adjusted individual measure savings by an *Adjustment Factor*. This factor accounts for the technical feasibility of efficiency measures (the percent of Virginia homes that satisfy the base case conditions and other technical prerequisites such as number of household members, heating fuel type, etc.) and the current market share of products that already meet the efficiency criteria. These assumptions are made explicit in Table B.2.

We then adjusted savings from the improved building envelope (insulation, windows, infiltration reduction, and duct sealing) to account for the reduced heating and cooling loads imparted by each of the envelope measures. Then we adjusted HVAC equipment savings to account for savings already realized from the reduced loads. Similarly, we adjusted water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers, low-flow shower heads, water heater pipe insulation, and faucet aerators. The multiplier for these adjustments is called the *Interaction Factor.*

We then adjusted replacement measures with lifetimes more than 17 years to only account for the percent turning over in 17 years, which represents the time period of the analysis. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation and duct sealing and testing. These retrofit measures therefore have 100% of measures “turning over.”

Equation 2 shows our calculation for efficiency resource potential, incorporating the three factors discussed above:

Equation 2. *Efficiency Resource Potential = ∑ (Annual Savings per Measure (kWh))* x *(Percent Turnover) x (Adjustment Factor)* x *(Interaction Factor)*

To calculate the efficiency resource potential savings by end-use in 2025, we present the savings as a percent of end-use electricity consumption (assuming current electricity consumption by end-use from AEO 2007). For the non-HVAC savings, we then multiply the “% savings” by projected residential electricity consumption for that end-use in 2025 to estimate the total savings potential in that year (see Equation 2). We assume that savings in the residential new construction sector cover projected new HVAC consumption, and therefore multiply the HVAC “% savings” by 2008 electricity consumption of this end use. See Equation 3 for a summary of how we derive the savings estimate for existing residential buildings.

Equation 3. *Efficiency Resource Potential by end-use in 2025 (GWh) = (% End-Use Savings)* x *(Electricity Consumption by sector in 2025* (GWh))*
* 2008 for HVAC

New Construction

We estimate savings from new construction in a similar manner as existing home measures. We looked at three levels of efficiency in new homes: 15%, 30%, and 50% better than current energy code. In estimating new home energy savings, we use a similar approach as building codes, which address HVAC consumption only. We estimated *% Applicable* by allocating each home into one of the three bins, with 15% predominating the early years and 50% the later years. See Equation four for a summary of how we calculate savings in new construction.

Equation 4. *Efficiency Resource Potential in 2025 (GWh) = (% HVAC savings per home) x (Percent Applicable) x (Projected new HVAC consumption between 2008 and 2025 (GWh))*

Measure Descriptions

In-home energy feedback monitor
Measure Description: A device installed inside the home that communicates with the electric meter and displays real-time electricity use information to occupants.

Basecase: Average metered home with no feedback mechanism other than monthly utility bills

Data Explanation: Total households applicable (67%) from RECS 2005 (EIA 2008b). Baseline electricity consumption is for an average household excluding multifamily buildings above four units from RECS (EIA 2003). Cost includes cost of product ($150) plus one hour of installation from Parker (2006). Percent savings (10%) from Stein (2004) and Hydro One (2006). Useful life (11 years) assumed to be similar to programmable thermostat, from ACEEE (2006). Penetration in residential sector technically achievable in all metered residential units.

Duct Sealing
Measure Description: Professional duct-sealing service suitable for retrofits and new construction, involving testing and either hand-applied or aerosol-based mastic (Jump 2006).

Basecase: Single-family home with a forced-air furnace and air conditioner.

Data Explanation: Baseline energy use from RECS (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 10% in each season (cooling and heating) is derived from 80% reduction in duct leakage (Jump 1996), which comprises half of the 20% of total HVAC energy use that can be associated with duct-related energy losses (the other half being by conduction, [Hammurlund 1992; Proctor 1993]). A cost of $750 is mature-market cost of Aeroseal, from Bourne, et al 1999. Applies to top 50% of residential homes with forced-air systems. Measure life is 20 years (SWEEP 2002)

Duct Insulation

Measure Description: R8 insulation applied to exposed ductwork in unconditioned spaces.

Basecase: Single-family home with a forced-air furnace and air conditioner with uninsulated ductwork passing through un-conditioned space (attic, un-finished basement, garage)

Data Explanation: Baseline energy use from RECS 2001 (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings from SWEEP, based on 10% heating/cooing energy use in forced-air system associated with conductive duct losses. Cost are $0.15–$0.20 per square foot of floor area. Floor area (1800 sq. ft) based off average floor area of colonial and ranch single family detached from ACEEE 1994. Applies to top 50% of residential homes with forced-air systems. Useful life is 25 years (SWEEP 2002).

Blower-Door Aided Infiltration Reduction

Measure Description: Application of foam and/or caulk around leakage areas applied and tested by a professional using a blower-door.

Basecase: Household with higher-than average heating and cooling energy use.

Data Explanation: Baseline energy use from RECS (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 10% from MT Screening Reports. Cost of $0.46/s.f. from XENERGY (2001). Useful life of 10 years from SWEEP 2002. Savings applied to percentage of homes that report drafts (40%), from RECS (EIA 2003).

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-11 assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R11-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.09) to incorporate savings from upgrading to R38. Total households applicable

(28%) average from RECS 2005 for house that are "well insulated" and houses that are "not well insulated" (EIA 2008b). Baseline energy use from RECS 2001 (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes.. Cost of $0.86/s.f. from DEER database (CEC 2005). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA 2003.

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-19 assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R19-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.34) to incorporate savings from upgrading to R38. Total households applicable (41%) from RECS 2005 for house that are "well insulated" (EIA 2008b). Baseline energy use from RECS 2001 (EIA 2003) depending on primary fuel use, plus a 25% adder representing high-use homes.. Cost of $0.86/s.f. from DEER database (CEC 2005). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA 2003.

Blow-in Cellulose Wall Insulation
Measure Description: Add blow-in cellulose insulation to un-insulated wall cavities

Basecase: Average-sized single-family home with wood-frame construction built before 1970.

Data Explanation: Total households applicable (16%) from RECS 2005 for houses that are "not well insulated" (EIA 2008b). Baseline energy use from RECS 2001 (EIA 2003), depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 15% and 1700 s.f. of uninsulated wall space are based on average of colonial and ranch single-family detached house types from 1994 ACEEE study on Gas EE opportunities in Long Island. Cost of $0.32/s.f. (unit and installation cost) from DEER database (CEC 2005). Useful measure life of 30 years from NYSERDA 2003.

Cool Roof Shingles
Measure Description: Roof shingles that meet ENERGY STAR residential requirements for reflectivity and thermal emittance due to light color or other material properties.

Basecase: Standard high-pitched residential roof with dark asphalt shingles

Data Explanation: Baseline electricity reflects cooling load only, from RECS 2001 (EIA 2003). Savings of 20% of cooling load and cost ($.10/s.f.) are from ACEEE Emerging Technologies analysis (Sachs et al 2004). Roof area (1400 sq. ft) based off assumption of 1000 sq. ft for attic area, multiplied by 1.4 (roof area generally 1.4 times greater than the area of the attic). Percent of homes applicable (86%) are the percent of households with asphalt shingles, from Dejarlais (2006). Market share (10%) and measure life (20 years) are from Sanchez et al. (2007).

ENERGY STAR Windows

Measure Description: Window replacements that meet regional ENERGY STAR requirements for U value and solar heat gain coefficient (SHGC).

Basecase: Replacement of 20 *single-pane* windows measuring approximately 15 s.f. each.

Data Explanation: Baseline energy use from RECS 2001 (EIA 2003). Savings (36%) from ratio of U-values associated with upgrading from single pane (U-value = 1.10) to Energy Star (U-value = .40), from Lekcie et al. 1981. Number of units (20) from ACEEE (2006). Incremental cost assumes 300 sq. ft. of windows at $1.50 per sq. ft. (NEEP 2006). Measure life (30) from SWEEP 2002. Percent of applicable households (50%) based on ENERGY STAR market share data.

High-efficiency Central Air Conditioner (cooling only)
Measure Description: SEER 15

Basecase: Current federal standard: SEER 13

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003). Percent savings (13%) and incremental cost from Energy Star calculator for Central Air Conditioners using Richmond, VA, as a proxy. Assumed not to be used in conjunction with programmable thermostat. Market share (9%) from Sanchez et al. (2007), assumed to be half of market share for Energy Star qualified unit with SEER = 14. Measure life (18 years) from DOE TSD (DOE 2001).

High-efficiency Heat Pump (heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003). Percent savings (14%) and incremental cost ($630) from Energy Star calculator for Air-Source Heat Pumps using Richmond, VA, as a proxy and apportioned based on heating hours for Richmond, VA. Assumed not to be used in conjunction with programmable thermostat. Market share (11%) from Sanchez et al. (2007), assumed to be half of market share for Energy Star qualified unit with HSPF = 8.2. Measure life (18 years) from DOE TSD (DOE 2001).

Efficient Furnace Fan (heating season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state HDD. Electricity savings (322 kWh, 60%) from Pigg (2008) and adjusted by ratio of national to state HDD. Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of seasonal savings, although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for heating season from ratio of heating season savings to total annual savings.

Efficient Furnace Fan (cooling season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state CDD. Electricity savings (164 kWh, 22%) from Pigg (2008) and adjusted by ratio of national to state CDD. Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of seasonal savings, although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for cooling season from ratio of cooling season savings to total annual savings.

Ground-Source Heat Pump
Measure Description: Closed ground-source heat pump with EER 14.

Basecase: Conventional air-source heat pump of SEER 13, HSPF 7.7

Data Explanation: Baseline energy use (for homes with electricity as primary fuel multiplied by 2 for high-use homes) and market penetration (of heat pumps) from RECS 2001(EIA 2003).New measure savings (21%) and cost ($2400) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with forced-air electric heat. Measure life (18 years) from Sachs 2007.

Ground-Source Heat Pump with Desuperheater (water heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline energy use and market penetration (of heat pumps) from RECS 2001 (EIA 2003). New measure savings (25%) and cost ($1,000) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with electric forced-air heat. Measure life (18 years) from Sachs 2007.

Efficient Electric Storage Water Heater
Measure Description: 50-gallon electric storage water heater, 0.93 EF

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Savings (3%) derived from EF increase. Incremental cost ($70) from Amann et al. (2007). Measure life (14 years) from NYSERDA 2003. Applies to houses with electric water heaters (EIA 2003). Market share (36%) estimated based on percent of products on the market meeting EF 0.93 in the GAMA product database (GAMA 2007).

Heat Pump Water Heater
Measure Description: Either add-on or integrated heat-pump that uses the evaporation-compression cycle to extract heat from surrounding air to heat water in a conventional storage tank. COP 2.0 or above.

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Percent Savings (60%) and measure life (14.5 years) are from Sachs, et al 2004. Incremental cost ($910) based off electric heat pump with COP=2.2, from Amann et al. (2007). Percent of households applicable (45%) include percentage of households with electric water heating multiplied by percentage of households that have three or more occupants.

High-efficiency showerheads
Measure Description: 2.0 gallons per minute (gpm) showerhead

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Showerhead meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003) depending on primary water heating fuel. Savings (10%) from Brown, et al 1987. Cost estimate ($23) for a low-cost, basic model from the DEER database (CEC 2005). Useful measure life of 9 years from Efficiency Vermont (2005). Percent of households applicable (45%) is percentage of households with electric water heating (average of Mid and South Atlantic), adjusted for current market share (40%) from BG&E customer appliance saturation survey.

Faucet Aerators
Measure Description: 1.5 gallons per minute (gpm) faucet aerator

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Baseline aerator meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003) depending on primary water heating fuel. Savings (2%) from Frontier Associates (2006). Cost estimate ($7) for a low-cost, basic model from the DEER database (CEC 2005). Percent of homes applicable (45%) is based on water heating fuel analyzed RECS 2001(EIA 2003), adjusted for current market share (35%) from BG&E customer appliance saturation survey.

Water Heater Pipe Insulation
Measure Description: Insulating 10 feet of exposed pipe in unconditioned space, ¾” thick.

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above).

Data Explanation: Baseline consumption from RECS 2001 (EIA 2003) depending on primary water heating fuel. Savings estimate from CL&P 2007. Costs ($28) from DEER Database based off $0.37 per linear foot equipment cost and $2 per linear foot installation cost (CEC 2005). Useful life of insulation 13 years from Efficiency Vermont (2005). Percent of homes applicable is based on water heating fuel analyzed.

Efficient Dehumidifier
Measure Description: Replacement dehumidifier that is ENERGY STAR certified based on the 2008 Energy Star specification.

Basecase: Dehumidifier that meets current (2005) federal energy standards.

Data Explanation: Baseline and incremental costs ($150) and electricity consumption from ENERGY STAR calculator. Percent savings (19%), measure life (12 years), and market share (60%) from Sanchez et al. (2007).

Efficient Room Air Conditioner

Measure Description: Energy Star Room A/C (10000 Btu unit at 10.8 EER).

Basecase: Room A/C that meets 2000 federal energy standards (10000 Btu at 9.8 EER)

Data Explanation: Baseline consumption, savings, and incremental cost from Energy Star savings calculator. Percent homes applicable (33%) based on saturation data and number of units per home from RECS 2005 (EIA 2008b). Measure life (13 years) from Sanchez et al. (2007). Market share (49%) from Energy Star 2006 appliance sales data.

Refrigerator Tier I
Measure Description: Replacement refrigerator that meets 2008 ENERGY STAR requirements (20% better than federal standard)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($64) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007). Market share (31%) from Sanchez et al. (2007).

Refrigerator Tier II
Measure Description: Replacement refrigerator that exceeds federal energy standard by 25% (CEE Tier 2)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($33) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007).

Horizontal-Axis Clothes Washer (appliances)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Incremental cost ($30) and electricity savings (20%) from ENERGY STAR savings calculator, isolating appliance energy savings only. Incremental cost ($200) apportioned based on percentage of electricity consumption not dedicated to water heating. Percent of homes based on appliance saturation data from RECS 2005 (EIA 2008b). 2006 market share (33%) from EPA (2007). Measure life (14 years) is from Sanchez et al. (2007).

Horizontal-Axis Clothes Washer (water heating)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Incremental cost ($270) and energy savings from ENERGY STAR savings calculator, isolating water heating energy savings only. Incremental cost ($200) apportioned based on percentage of electricity consumption dedicated to water heating. Percent of homes based on appliance saturation data from RECS 2005 (EIA 2008b). 2006 market share (33%) from EPA (2007). Measure life (14 years) is from Sanchez et al. (2007).

Efficient Dishwasher (appliances)
Measure Description: Dishwasher meeting 2007 CEE Tier 2 requirement, 0.68 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and electricity savings from DOE 2007 Technical Support Document, isolating appliance energy savings only. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. (2007). Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Efficient Dishwasher (water heating)
Measure Description: Dishwasher meeting 2007 CEE Tier 2 requirement, 0.68 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and energy savings from DOE 2007 Technical Support Document, isolating water heating energy savings only. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. (2007). Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Ceiling Fan
Measure Description: ENERGY STAR certified ceiling fan

Basecase: Standard ceiling fan as defined by ENERGY STAR

Data Explanation: Baseline consumption, new measure consumption, and incremental cost from ENERGY STAR calculator. 2.21 units per household assumed from RECS 2005 (EIA 2008b). Baseline and new measure consumption, as well as units per household, specific to South Atlantic region. Measure life (10 years) and market share (24%) are from Sanchez et al. (2007).

Compact Fluorescent Lighting
Measure Description: Savings from the 17-watt equivalent to baseline lamp (75%) applied to 80% of baseline incandescent lamp hours.

Basecase: Baseline house requires 25,659 incandescent lamp-hours per year; average incandescent wattage is 63 watts based on 2001 federal government lighting inventory survey (DOE 2002).

Data Explanation: Measure of 80% replacement by lamp-hours is ACEEE assumption based on a conservative estimate of feasible applications. Applies to all households. Market share (10%) from ACEEE estimate based on EPA's estimate of Energy Star lamp sales in 2007 and ACEEE's estimate of total lamp sales.

Active Mode Efficiency for Televisions
Measure Description: Active mode standard for televisions equivalent to ENERGY STAR Draft 2 specification

Basecase: Average of all TVs from ENERGY STAR data set that do not pass Draft 2 specification

Data Explanation: Baseline and new measure savings data are from Chase (2008) and are based on the data set that was used in the ENERGY STAR Draft 2 TV specification revision. Measure life from Appliance Magazine (September 2007). Market share data from 2007 Draft 2 Energy Star documents (www.energystar.gov). No reliable incremental cost data is available. The cost variance among a range of non-energy-related TV components is dramatically more significant to the consumer, resulting in very low cost per kWh saved per household. Our estimate is set to result in a levelized cost similar to that for the 1-watt standby measure.

Low Power Set-Top Boxes
Measure Description: Require digital set-top boxes to have a maximum sleep state power level of 10 watts and to automatically enter sleep mode after 4 hours without user input.

Basecase: Typical house with 1.9 set top boxes.

Data Explanation: All data except cost is from Rainer (2008). No reliable incremental cost data is available. In the case of set-top boxes, efficiency measures are largely software-related, likely resulting in very low cost per kWh saved per household. Our cost estimte is set to result in a levelized cost similar to that for TVs.

One-Watt Standby for All Household Electronics
Measure Description: All new electronics devices required to have maximum “off” mode power level of 1 watt.

Basecase: Typical house with 17-20 devices.

Data Explanation: Baseline consumption, savings, incremental costs and measure life available from ACEEE 2004 emerging technologies analysis (Sachs et al. 2004). Penetration of new measure assumed by averaging market shares of all ENERGY STAR home electronics equipment.

ENERGY STAR New Home
Measure Description: New home that uses 15% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($805) and market share (5%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Advanced Building Code New Home
Measure Description: New home that uses 30% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($1480) and market share (0%) from personal communication wtih Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Tax-Credit-Eligible New Home
Measure Description: New home that uses 50% less energy than code.

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($2775) and market share (0%) from personal communication wtih Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

C.2.Commercial Buildings

C.2.1. Baseline End-Use Electricity Consumption

To estimate the resource potential for efficiency in commercial buildings in Virginia, we first develop a disaggregate characterization of baseline electricity consumption in the state for current electricity use and a reference load forecast (see Table C.1 below). Highly disaggregated commercial electricity consumption data is unfortunately not available at the state level. To estimate these data, we start with current electricity consumption for the Virginia commercial sector (EIA 2008) and a forecast out to 2025 based on PJM forecasts, and we disaggregate by end-use using average regional data from CBECS 2003 (EIA 2006b) and AEO 2007 (EIA 2007c).

Table C.1. Baseline Commercial Electricity Consumption by End-Use (GWh)

End-Use	2009	%	2015	%	2025	%
Heating	1,837	4%	2,141	4%	2,339	3%
Ventilation	5,792	12%	6,751	12%	7,902	12%
Cooling	2,463	5%	2,871	5%	3,292	5%
HVAC Subtotal	*10,092*	*21%*	*11,763*	*21%*	*13,534*	*20%*
Water Heating	1,293	3%	1,507	3%	1,592	2%
Refrigeration	2,979	6%	3,472	6%	3,959	6%
Lighting	16,945	35%	19,750	35%	22,717	33%
Office Equipment	6,970	14%	8,124	14%	10,810	16%
Appliances and Other	10,215	21%	11,905	21%	15,473	23%
Total	48,494	100%	56,522	100%	68,083	100%

Next, we estimate commercial square footage in the state using electricity intensity data (kWh per square foot) by census region from CBECS (EIA 2006b). We use an average of the South Atlantic (18.3 kWh/s.f.) and Mid Atlantic (12.5 kWh/s.f) census regions to estimate an overall electricity intensity for the state of Virginia of 15.4 kWh per square foot. Total electricity consumption in the state divided by the electricity intensity provides an estimate of commercial floorspace. Using this methodology, we estimate 3,149 million square feet of commercial floorspace in the state.

C.2.2. Measure Cost-Effectiveness

We then analyze 33 efficiency measures for existing commercial buildings and 3 new construction whole-building measures to examine the cost-effective energy efficiency resource potential. For each efficiency measure, we estimate electricity savings (*Annual Savings per Measure)* and incremental cost (*Measure Cost)* in a "replacement on burnout scenario," which assumes that the product is replaced or the measure is installed at the end of the measure's useful life. Savings and costs are incremental to an assumed *Baseline Measure*. We estimate savings (kWh) and costs ($) on a per-unit and/or a per-square foot commercial floorspace basis. For each measure we also assume a *Measure Lifetime*, or the estimated useful life of the product.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than 8.4 cents/kWh, the estimated current average commercial cost of electricity in Virginia. The estimated CCE for each efficiency measure, which assume a discount rate of 5%, are shown in the measure descriptions below. Equation 1 shows the calculation for cost of conserved energy.

Our assumed *Baseline Measure*, *Annual Savings per Measure, Measure Cost, Measure Lifetime, and CCE* are reported for each of the efficiency measures in the list of measure descriptions below. We group the 33 efficiency measures for existing commercial buildings by end-use and list the 3 new building measures last.

Equation 1. *CCE = PMT ((Discount Rate)*, *(Measure Lifetime)*, *(Measure Cost)) / (Annual Savings per Measure (kWh))*

C.2.3. Total Statewide Resource Potential

For each measure, we then derive *Annual Savings per Measure* on a per square foot basis *(kWh per square foot)* for the applicable end-use. For measures that we only have savings on a per-unit or per-building basis, we first derive the percent savings and multiply by the *Baseline Electricity Intensity* for that end-use. The assumed baseline intensities for each end use are shown in Table C.2. As an example, for a specific lighting measure we multiply its percent savings by the baseline electricity intensity (kWh per square foot) for the lighting end-use.

Table C.2. Commercial End-Use *Baseline Electricity Intensities* (kWh per s.f.)

End-Use	2009
Heating	0.6
Ventilation	1.8
Cooling	0.8
HVAC Subtotal	3.2
Water Heating	0.4
Refrigeration	0.95
Lighting	5.4
Office Equipment	2.2
Appliances and Other	3.2
Total	15.4

To estimate the total efficiency resource potential in existing commercial buildings in Virginia by 2025, we must first adjust the individual measure savings by an *Adjustment Factor* (See Equation 2). This factor accounts for two adjustments: the technical feasibility of efficiency measures, called the *Percent Applicable* (the percent of Virginia floorspace that satisfy the base case conditions and other technical prerequisites such as heating fuel type and cooling equipment, etc); and the *Current Market Share*, or the percent of products that already meet the efficiency criteria. These assumptions are outlined in each of the efficiency measure descriptions below.

Equation 2. *Adjustment Factor = Percent Applicable x (1-Current Market Share).*

We then adjust total savings for interactions among individual measures. For example, we must adjust HVAC equipment savings downward to account for savings already realized through improved building envelope measures (insulation and windows), which reduce heating and cooling loads. Similarly, we adjust water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers. The multiplier for these adjustments is called the *Interaction Factor.*

Finally, we adjust replacement measures with lifetimes more than 7 and 17 years to only account for the percent turning over in 7 and 17 years, which represents the benchmark years of 2015 and 2025, respectively. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures "turning over."

We then calculate the resource potential for each measure in the state using Equation 3, which takes into account all of the adjustments described above. The sum of the resource potential from all measures is the overall energy efficiency resource potential in the state's commercial buildings sector.

Equation 3. *Efficiency Resource Potential in 2015 and 2025 (GWh) = (Annual Savings per Measure (kWh per square foot)) x (Commercial floor space in Virginia in millions of square feet) x (Percent Applicable)* x *(Interaction Factor) x (Percent Turnover)*

C.2.4. Efficiency Measures

Table C.3. shows the thirty-six efficiency measures examined for this analysis, grouped by end-use costs, savings (kWh) per product or square foot, *Percent Applicable, Interaction Factor, Percent Turnover,* and total savings potential (GWh) in 2025. Detailed descriptions of each measure are given below, grouped by end-use.

HVAC

1. Duct testing and sealing

Measure Description: Testing and sealing air distribution ducts saves energy. This measure assumes supply and return ducts will be fully sealed.

Basecase: The basecase assumes air loss of 29% of fan flow, and leakage of 15% of the system flow.

Data Explanation: 24,828 kWh savings per unit are for an average 21,721 ft^2 retail or education building. Percent savings of 6% apply to whole-building electricity consumption (SWEEP 2002). An incremental cost of $3,375, which assumes $300 per ton, a 10 year lifetime, and 25% applicability are ACEEE estimates. The levelized cost is calculated to be 1.8 cents/kWh.

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2. Cool roof

Measure Description: This measure involves installing a sun-reflective coating on the roof of a building with a flat top. This reduces air conditioning energy loads by reducing the solar energy absorbed by the roof.

Basecase: The baseline electricity intensity for HVAC end uses in Virginia (4.3 kWh/ft^2/year) is used as the basecase.

Data Explanation: We assume 4% HVAC load savings (ACEEE 1997) off the baseline electricity intensity for HVAC end-uses in MD (CBECS 2003), an incremental cost of $0.25 per ft^2 (SWEEP 2002), and a 20-year average lifetime (SWEEP 2002). Percent applicable (80%) is an ACEEE estimate. Savings and cost per unit are based on a 15,000 ft^2 building from ACEEE Mid-Atlantic study (1997). The levelized cost is calculated to be 5.5 cents/kWh.

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3. Roof insulation

Measure Description: Fiberglass or cellulose insulation material in roof cavities will reduce heat transfer, though the type of building construction limits insulation possibilities. R-values describe the performance factor for insulation levels.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percentage of savings.

Data Explanation: We assume 3% savings and a post-savings electricity intensity of 0.28 kWh/ft^2/year, based on an average of four building types (ACEEE 1997). An average lifetime of 20 years and an incremental cost of 12 cents/ft^2 were also assumed.

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4. Double Pane Low-Emissivity Windows

Measure Description: Double-pane windows have insulating air- or gas-filled spaces between each pane, which resist heat flow. Low-emissivity (low-e) glass has a special surface coating to reduce heat transfer back through the window, and a window's R-value represents the amount of heat transfer back through a window.
Low-e windows are particularly useful in climates with heavy cooling loads, because they can reflect anywhere from 40% to 70% of the heat that is normally transmitted through clear glass. The Solar Heat Gain Coefficient (SHGC) represents the fraction of solar energy transferred through a window. For example, a low-e window with a 0.4 SHGC keeps out 60% of the sun's heat.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percent savings.

Data Explanation: Percent savings of 3% apply to whole-building electricity consumption (ACEEE 1997). Incremental costs assume $2 per window (SWEEP 2002). A measure life of 25 years is from SWEEP 2002. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 3.4 cents/kWh.

5. Ventilation fans with Variable-Frequency Drive

Measure Description: Variable Frequency Drive (VFD) controls the speed of a motor by adjusting the frequency of incoming power. By controlling the speed of a motor, the output of the system can be matched to the requirements of the process, thereby improving efficiency.

Basecase: The basecase unit is a 50 hp fan with 60% load factor, 93% efficiency (ODP, EPAct levels) and 3653 operating hours/year (21-50 hp category from ACEEE standards savings analysis).

Data Explanation: We assume 25% savings applies to ventilation only (ACEEE 1997), which is a conservative estimate. We estimate a $6,650 incremental cost, which assumes $125/hp for VFD and $8/hp for a better fan, and a 10-year measure life (SWEEP 2002). ACEEE estimates that this measure can apply to 40% of systems. The levelized cost is calculated to be 3.9 cents/kWh.

6. High-Efficiency Unitary AC/HP
65,000 Btu — 135 Btu
135,000 Btu — 240,000 Btu

Measure Description: Unitary packaged air conditioners and heat pumps represent the heating, ventilating, and air conditioning (HVAC) equipment class with the greatest energy use in the commercial sector in the United States, and are used in approximately 48 percent of the cooled floor space in the commercial sector (DOE 2004). High efficiency units have a greater energy efficiency ratio (EER).

Basecase: The assumed basecase unit meets the 2010 federal efficiency standard. Baseline electricity intensity for this end-use, 3 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: This measure includes two size ranges; the first is 65,000 Btu to 135,000 Btu, and the second is 135,000 btu to 240,000 Btu. The measure assumes a 12 EER unit relative to the 2010 federal standard, which ranges from about 10.4 EER to 11.2 EER, depending on the unit type and size. The energy savings average 1,070 kWh (7.2%) for the smaller unit and 3,371 kWh (10.8%) for the larger unit. We assume a measure lifetime of 15 years (LBNL 2003). Incremental costs (average $629 for 65 kBtu to135 kBtu and $1,415 for 135 kBtu to 240 kBtu) are derived from DOE's Technical Support Document (DOE 2004). Percent applicable (33% for 65 kBtu to135 kBtu), and the percent of floorspace with cooling from unitary equipment are also from DOE's Technical Support Document (DOE 2004). The levelized cost is calculated to be 4–5.7 cents/kWh, depending on unit type and size.

7. High-Efficiency Packaged Terminal AC/HP

Measure Description: PTACs and PTHPs are self-contained heating and air-conditioning units encased inside a sleeve specifically designed to go through the exterior building wall. The basic design of a PTAC is comprised of a compressor, an evaporator, a condenser, a fan, and an enclosure. They are primarily used to provide space conditioning for commercial facilities such as hotels, hospitals, apartments, dormitories, schools, and offices.

High-efficiency units have a higher energy efficiency ratio (EER) for cooling units and coefficient of performance (COP) for heat pumps.

Basecase: Consistent with all HVAC-related measures, the baseline electricity intensity is 3 kWh per ft^2, which is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume that high efficiency units save an average of 7.8%, or 226 kWh per unit, relative to a basecase, which is based on an ACEEE submission to ASHRAE using web data. The measure life is 15 years (ASHRAE 90.1-1999). Percent applicable is 5%, which is the percent of cooling floorspace from packaged terminal units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

8. Efficient Room Air Conditioner

Measure Description: An Energy Star room AC must be at least a 10% improvement over the 2000 federal standard (an average 8000 Btu unit must have a 10.8 EER).

Basecase: The assumed basecase unit is a room A/C that meets 2000 federal energy standards (an average 8000 Btu unit has a 9.8 EER) and uses an average of 1212 kWh per unit. Baseline electricity intensity for this end-use, 2.5 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume an Energy Star room AC uses 1100 kWh per year, saves 9% of basecase energy, and has an incremental cost of $30 (Energy Star calculator). The percentage of homes applicable (8%) is based on saturation data, and the number of units per home is from RECS 2005 (EIA 2008b). We assume a measure life of 9 years (Energy Star calculator), a current market share of 52% (EPA 2007), and percent applicable assumes 4% percent of cooling floorspace uses room AC units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

9. High-Efficiency Chiller

Measure Description: "Chillers" are the hearts of very large air-conditioning systems for buildings and campuses with central chilled water systems. A centrifugal chiller utilizes the vapor compression cycle to chill water and reject the heat collected from the chilled water plus the heat from the compressor to a second water loop controlled by a cooling tower.

Basecase: The basecase unit assumes 0.634 kW/ton T24 from DEER for an average 150 ton system and 1,593 national average full-load operating hours from the ASHRAE 90.1-1999 analysis. Baseline electricity intensity for this end-use, 3.2 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume the new measure has 20% savings, which is derived from estimates provided in SWEEP 2002 and ACEEE 1997. The lifetime estimate of 23 years is from the ASHRAE Handbook (HVAC Applications). Incremental costs are $9,900 and assume a 150 ton average unit (CEC 2005). Percent applicable (33%) assumes percentage of cooling floorspace using chillers (ADL 2001). The levelized cost is calculated to be 2.4 cents/kWh.

10. Dual-Enthalpy Economizer

Measure Description: Economizers modulate the amount of outside air introduced into the ventilation system based on the relative temperature and humidity of the outside and return air. If the enthalpy, or the latent and sensible heat, of the outside air is less than that of the return air when space cooling is required, then the outside air is allowed to reduce or eliminate the cooling requirement of the AC equipment.

Basecase: Baseline electricity intensity, 3 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: Savings per unit assume 276 kWh (20% savings) per ton for an average 11-ton unit (CL&P 2007). Average measure life is 10 years (CL&P 2007). Incremental costs per unit are from NYSERDA 2003.

Percent applicable is the portion of cooling square footage represented by packaged AC and HP units, and assumes that 90% of these unitary systems could benefit from economizers (ACEEE estimate). It also assumes a 5% current market share (ACEEE estimate). The levelized cost is calculated to be 3.8 cents/kWh.

11. HVAC Tune-up

Measure Description: Most HVAC technicians lack interest, training, equipment and methods to perform quality refrigerant charge and airflow (RCA) tune-ups. Because many new and existing air conditioners have improper RCA, which reduces efficiency, there is significant potential for energy savings by diagnosing and correcting RCA.

Basecase: The assumed basecase unit is a 4.5 ton commercial unitary AC/HP per California program experience (CPUC 2006), estimated to use 8,396 annual kWh per the unitary AC/HP measure. The base electricity intensity for the HVAC end-use is 3 kWh/ ft^2, the average for small buildings less than 25,000 ft^2, for which this measure is applicable.

Data Explanation: We assume 11% percent savings from this measure according to California's DEER database (CEC 2005) and the California Refrigerant and Air Charge (RCA) program report (CPUC 2006). We assume that 60% of units have improper RCA (CPUC 2006), and therefore this measure is applicable to 60% of unitary HVAC units in buildings less than or equal to 25,000 ft^2 (CBECS 2003; average of south and mid-Atlantic regions). We estimate an average measure life of 3 years, as units need to be periodically re-tuned. We assume a cost of $158 for this measure, based on a $35/ton labor cost (CEC 2005) and an assumed 4.5-ton unit. The levelized cost is calculated to be 6.3 cents/kWh.

12. Energy Management System (EMS)

Measure Description: An Energy Management System (EMS) is a computerized system that collects, analyzes and displays information on HVAC, lighting, refrigeration, and other commercial building subsystems to aid commercial building and facility energy managers, financial managers, and electric utilities in reducing energy use in buildings.

Basecase: Baseline electricity intensity is the average HVAC end-use consumption in Virginia, estimated from CBECS (EIA 2006b) to be the average of consumption in the Mid- and South-Atlantic regions.

Data Explanation: We assume 10% cooling savings and 7.5% heating and ventilation savings from an installed EMS (NYSERDA 2003). We estimate a 15-year measure life for the system. We assume total incremental costs of $19,333 for a 60,000 ft^2 building, which is derived from NYSERDA 2003, and assume a third of this ($6,380) for this measure by assuming the cost is spread equally among electric HVAC, gas HVAC and lighting. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 3.6 cents/kWh.

13. Retrocommissioning

Measure Description: Commercial building performance tends to degrade over time, and many new buildings do not perform as designed, requiring periodic upgrades to restore system functions to optimal performance. Retrocommissioning (RCx) is a systematic process to optimize building performance through O&M tune-up activities and diagnostic testing to identify problems in mechanical systems, controls, and lighting. The best candidates for RCx are buildings over 50,000 or 100,000 ft^2.

Basecase: The baseline is electricity intensity for HVAC and lighting end-uses in buildings greater than 50,000 ft^2 (10 kWh/ ft^2), which is based on data from CBECS (EIA 2006b). We take the average of the Mid-Atlantic and South Atlantic regions to estimate electricity intensity in Virginia buildings.

Data Explanation: We assume 10% savings for HVAC and lighting end-uses (Sachs et al. 2004) in all commercial floorspace for buildings greater than 100,000 ft^2, and 50% of floorspace in buildings 50,000 ft^2 or greater based on data from CBECS (EIA 2006b). Xcel Energy's RCx program results estimate an average RCx useful life of 7 years (Xcel Energy 2006). We assume a $0.25 cost per ft^2 (Sachs et al. 2004). The levelized cost is calculated to be 4.3 cents/kWh.

14. Demand-Controlled Ventilation

Measure Description: Often, HVAC systems are designed to supply ventilated air based on assumed occupancy levels, resulting in over-ventilation. Demand-controlled ventilation monitors CO_2 levels in different zones and delivers the required ventilation only when and where it is needed.

Basecase: The basecase is standard ventilation electricity consumption for a 50,000 ft^2 office building, or about 40,000 kWh/year (Sachs et al. 2004). Baseline electricity intensity for this end-use, 0.8 kWh per ft^2, is the estimated ventilation consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume 20% savings for this measure (ET 2004). Energy use per unit is 32,000 kWh/year, assuming a 50,000 ft^2 building (Sachs et al. 2004). The lifetime estimate is 15 years, and incremental costs are $3,450 (Sachs et al. 2004). The measure is applicable to 90% of larger (60%) cooling units (Sachs et al. 2004). The levelized cost is calculated to be 4.2 cents/kWh.

Water Heating Measures

15. Heat Pump Water Heater

Measure Description: A heat pump water heater uses electricity to move heat from one place to another, rather than a less efficient electric resistance water heater which uses electricity to generate the heat directly. The heat source is the outside air or air in the basement where the unit is located.

Basecase: The basecase is standard electric water heating, with electricity consumption of 22,831 kWh/year (derived from energy savings and percent savings). Baseline electricity intensity for this end-use, 0.41 kWh per ft^2, is the estimated water heating consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: We assumed a 62% savings, based on a simple coefficient of performance ratio. The assumed 14,155 kWh savings, $4,067 incremental cost, and 12 year lifetime estimates are from NYSERDA 2003. Percent applicable is based on engineering estimates for NYSERDA 2003, which assumes the measure is applicable to 70% of food service floorspace and 30% of lodging, education, and health care floorspace. Percent applicable is then multiplied by 2, since these building types are more energy and hot-water intensive than the average commercial building. The levelized cost is calculated to be 3.2 cents/kWh.

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16. Efficient Commercial Clothes Washer (water heating portion)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water, and as a result reduces water heating loads. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represents about 80% of products on Energy Star's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,136 kWh annually for water heating, which is derived from DOE 2007. Baseline electricity intensity for this end-use is 0.55 kWh/ft^2/year (water heating portion only).

Data Explanation: Savings on electric water heating from this measure assume a 2.0 MEF clothes washer uses an average 431 kWh annually, for a 62% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 17% of units that have electric water heating, and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Virginia based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Refrigeration Measures

17. Efficient Walk-In Refrigerators & Freezers

Measure Description: Walk-in refrigerators and freezers (walk-ins) are medium and low-temperature refrigerated spaces that can be walked into, and that are used to maintain the temperature of pre-cooled materials (not to rapidly cool down materials from warmer temperatures). A high-efficiency walk-in is defined as meeting the 2004

CEC standard for walk-ins. This includes prescriptive requirements such as higher levels of insulation, motor types, and the use of automatic door-closers (Nadel et al. 2006).

Basecase: The baseline energy use for an average walk-in is 18,859 kWh/year (Nadel et al. 2006). Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: For a high-efficiency walk-in unit, we assume 44% savings over a baseline unit, or 8220 kWh/year, $957 incremental cost, and a 12 year measure lifetime (Nadel et al. 2006), which are based on a PG&E CASE study (2005). We estimate percent applicable as the 18% of refrigeration energy use attributed to walk-ins (ADL 2006) and estimate a 50% current market share of high-efficiency products (ACEEE estimate). The levelized cost is calculated to be 1.3 cents/kWh.

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18. Efficient Reach-In Coolers & Freezers

Measure Description: This measure includes high-efficiency packaged commercial reach-in refrigerators and freezers with solid doors, and refrigerators with transparent doors such as beverage merchandisers. High-efficiency units are those that meet the CEE Tier 2 performance standard, as estimated in PG&E 2005.

Basecase: We assume a baseline unit, which is one that meets that upcoming (2009 or 2010) federal standard, uses 4,027 kWh per year. This is weighted by sales of unit type per PG&E 2004. Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: The savings estimate for a high-efficiency unit, 31% savings or 1,268 kWh per year, is a weighted average of different types of reach-ins that meet CEE's Tier 2 performance standard (PG&E 2005). We estimate an average lifetime of 9 years and an incremental cost of $341, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to reach-ins and beverage merchandisers, or 17% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005. The levelized cost is calculated to be 2.2 cents/kWh.

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19. Efficient Ice-Maker

Measure Description: Commercial ice makers, which are used in hospitals, hotels, and food service and preservation, have energy savings potential largely in their refrigeration systems. We assume an efficient icemaker meets CEC's Tier 2 level of energy savings, which incorporate improved compressors, heat exchangers, and controls, as well as better insulation and gaskets.

Basecase: The baseline energy use, 3,338 kWh per year, is a weighted average of different types of ice-makers that meet the 2010 standard. Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: The 16% savings estimate for a high-efficiency unit, or 542 kWh per year, is a weighted average of different types of ice-makers that meet CEC's tier 2 energy savings (PG&E 2005). We estimate an average lifetime of 10 years and an incremental cost of $100, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to ice-makers, or 10% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005 and ACEEE judgment. The levelized cost is calculated to be 2.4 cents/kWh.

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20. Efficient Built-up Refrigeration System

Measure Description: Built-up or supermarket refrigeration systems are primarily made up of refrigerated display cases for holding food for self-service shopping, as well as machine room cooling technologies. More efficient built-up systems include improved machine room technologies (evaporative condensers, mechanical sub-cooling, and heat reclaim), high-efficiency evaporative fan motors, hot gas defrost, liquid-suction heat exchangers, antisweat control, and defrost control.

Basecase: The measure baseline is 1,600,000 kWh for a 45,000 ft^2 supermarket with a built-up refrigeration system. Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: Per-unit savings of 336,000 kWh (21%) are from ADL 1996 and assume an average new 45,000 ft^2 supermarket with a 5-year payback. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 33% (ADL 1996). Incremental cost ($37,000) and lifetime (10 years) are from ADL 1996. The levelized cost is calculated to be 1.3 cents/kWh.

21. Efficient Vending Machine

Measure Description: Energy Star vending machines must consume 50% less energy than standard machines. Under the Tier II ENERGY STAR level, this translates to a maximum energy consumption of 6.53 kWh/day for a 650-can machine.

Basecase: A Tier I ENERGY STAR level vending machine is assumed to be the basecase. On average, it uses 2,816 kWh per year (Energy Star calculator for a 600 can machine). Baseline electricity intensity for this end-use, 0.95 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA's commercial buildings survey.

Data Explanation: Per unit savings of 18% (509 kWh/year) are estimated from ASAP 2007 based on Energy Star calculator estimates. Likewise, an incremental cost of $30, and a lifetime estimate of 10 years are from ASAP 2007. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 13% (NYSERDA 2003). Stock estimates are from the 2005 TSD (DOE 2005). The levelized cost is calculated to be 0.8 cents/kWh.

22. Vending Miser

Measure Description: A Vending Miser is an energy control device for refrigerated vending machines. Using an occupancy sensor, the control turns off the machine's lights and duty cycles the compressor based on ambient air temperature.

Basecase: The basecase unit is an efficient vending machine that meets the Energy Star tier II level and uses 2,309 kWh per year (Energy Star calculator for a 600 can machine). Baseline electricity intensity is for the refrigeration end-use (0.95 kWh/ ft^2).

Data Explanation: We assume 35% savings for this measure based on manufacturer data (usatech.com 2008), an incremental cost of $167 (NYSERDA 2003), and a measure life of 10 years (NYSERDA 2003). The levelized cost is calculated to be 2.7 cents/kWh.

23. Efficient Hot Food Holding Cabinets

Measure Description: Commercial hot food holding cabinets are used in the commercial kitchen industry primarily for keeping food at safe serving temperature, without drying it out or further cooking it. These cabinets can also be used to keep plates warm and to transport food for catering events. High efficiency models differ mainly in that they are better insulated.

Basecase: The basecase unit is an uninsulated cabinet that consumes 5,190 kWh per year. This was calculated from CASE (2004) using a simple average of three sizes of cabinets, and then weighting the average using CASE figures for insulated cabinets.

Data Explanation: The energy savings from an insulated holding cabinet are 1,815 kWh per year (35% savings), with an incremental cost of $453, and an estimated 15 year lifetime (ASAP 2007, based on PG&E CASE study (2004)). Percent applicable refers to the 25% of holding cabinets that are currently uninsulated (ASAP 2007, based on PG&E CASE study (2004)). The levelized cost is calculated to be 2.4 cents/kWh.

24. Efficient Commercial Clothes Washer (excluding hot water energy)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represent about 80% of products on Energy Star's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,530 kWh annually for non-water heating uses, which is derived from DOE 2007.

Data Explanation: Electric savings from this measure assume a 2.0 MEF clothes washer uses an average 1,191 kWh annually, for a 22% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 39% of units that have electric dryer heating (removal of moisture from clothes), and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Virginia based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Lighting Measures

25. Fluorescent Lighting Improvements

Measure Description: The new measure assumes extra-efficient ballasts and high-lumen lamps are installed with no change in light level (low ballast factor).

Basecase: Basecase watts per square foot reflect current installed fixtures. This includes 84,000 annual tube fluorescent kWh used per average 14,000 ft^2 commercial building (Navigant 2002). On average, fluorescent lights are operated 9.7 hours/day. We assume 2-lamp standard T8 fixtures and electronic ballasts as the baseline, plus a small number of existing 3-lamp T12 fixtures with magnetic ballasts that are not likely to be replaced in the absence of programs over the time horizon.

Data Explanation: We assume a percent savings of 27%.The incremental costs are $2 extra per ballast, and $1 extra for each of 2 lamps. The percent applicable (56%) is the fluorescent percent of total commercial lighting kWh (Navigant 2002). The levelized cost is calculated to be 0.6 cents/kWh.

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26. HID Lighting Improvements

Measure Description: Metal halide lamps produce light by passing an electric arc through a mixture of gases. Efficiency improvements in metal halide lamps include pulse start lamp technology, electronic ballasts, and improved fixtures.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: The new measure savings and costs are from a PG&E CASE study on Metal Halide Lamps & Fixtures (PG&E 2004). Energy savings were 447 kWh per year (26%), and incremental costs were $60. Percent applicable (12%) is the percentage of commercial electricity use for lighting that comes from HIDs (Navigant 2002). The levelized cost is calculated to be 6.3 cents/kWh.

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27. Replace Incandescent Lamps

Measure Description: The new measure assumes that 4 average 75 W incandescent lamps are replaced with 23 W CFLs. It is assumed that the lights operate 9.5 hours per day.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are 180 kWh per year, or 69%. Incremental costs include $10 in the cost of 4 CFLs, but save $32 in labor for replacing the bulbs, so the result is a cost savings. Percent applicable assumes that 32% of commercial electricity use for lighting is from incandescents (Navigant 2002), and ACEEE estimates that 70% of sockets are applicable for the new measure. The levelized cost is calculated to be -1.3 cents/kWh.

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28. Occupancy Sensor for Lighting

Measure Description: Installation of occupancy sensors can greatly reduce lighting energy demands in commercial spaces, by automatically turning off lights in unoccupied spaces.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings of 361 kWh per year (NYSERDA 2003) assumes 30% energy reduction in individual offices and rooms and 7.5% reduction in open spaces (ACEEE estimate). Incremental cost ($48) and lifetime (10 years) estimates are from NYSERDA 2003. Percent applicable (38%) is from ACEEE 2004. The levelized cost is calculated to be 1.7 cents/kWh.

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29. Daylight Dimming System

Measure Description: A daylight dimming system automatically dims electric lights to take advantage (or “harvest”) natural daylight.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are estimated to be 143 kWh per year, or 35% (NYSERDA 2003). Savings apply for lamps on the perimeters of buildings (25% applicable—PIER 2003). Incremental cost ($68) and lifetime (20 years) estimates are from NYSERDA (2003). The levelized cost is calculated to be 3.8 cents/kWh.

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30. Outdoor Lighting—Controls

Measure Description: This measure includes a variety of lighting control technologies for exterior lights.

Basecase: No basecase data was available for this measure.

Data Explanation: We assume a savings of 174 kWh, or 20%, from lighting controls. Incremental costs of $43 are from DEER 2001 and assume each control on average controls three fixtures. Percent applicable of 30% is an ACEEE estimate. The levelized cost is calculated to be 2.5 cents/kWh.

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31. Office Equipment

Measure Description: This measure assumes a high-efficiency fax, printer, computer display, internal power supply, and a low mass copier.

Basecase: Baseline electricity use is 2886 kWh per year (NYSERDA 2003). Baseline electricity intensity for this end-use, 2.2 kWh per ft^2, is the estimated office equipment energy consumption in commercial buildings in Virginia. This assumes the average of buildings in the South Atlantic and Mid Atlantic regions from EIA’s commercial buildings survey.

Data Explanation: Energy savings were 1410 kWh per year (49%), lifetime was 5 years, and incremental costs were $20. Percent applicable is estimated to be (50%) (NYSERDA 2003). The levelized cost is calculated to be 0.3 cents/kWh.

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32. Efficient New Building (15% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 9.8 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Virginia, derived from data for buildings built from 2000-2003 (EIA 2006b).

Data Explanation: Incremental cost of $0.35 per ft^2 and measure life of 17 years are from NGRID 2007. Percent applicable of 18% for this new buildings measure assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.1 cents/kWh.

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33. Efficient New Building (30% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 9.8 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new VA buildings, derived from data for buildings built from 2000-2003 (EIA 2006b).

Data Explanation: In New York, estimates show that commercial buildings can reach 30% beyond code at an investment of $0.54/kWh. To be conservative, we estimate $0.70/kWh by doubling the costs of a 15%-beyond-code building. Measure life of 17 years is from NGRID 2007. Percent applicable of 35% for 30% savings new buildings assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.1 cents/kWh.

34. Tax-Credit Eligible Building (50% Savings)

Measure Description: A federal tax incentive is available for new buildings that are constructed to save at least 50% of the heating, cooling, ventilation, water heating, and interior lighting cost of a building that meets ASHRAE standard 90.1-2001.

Basecase: Basecase of 9.8 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Virginia, derived from data for buildings built from 2000-2003 (EIA 2006b).

Data Explanation: Incremental costs of $3.00 per ft^2 are from ACEEE 2004. Measure life of 17 years is from NGRID 2007. The levelized cost is calculated to be 5.4 cents/kWh.

Table C.3. Commercial Energy Efficiency Measure Characterizations

Measures	End-Use	Measure Life (Years)	Annual kWh svgs per unit	2007 Virginia Stock	kWh svgs per s.f.	Incremental cost per unit	Incremental cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjustment Factor	% Turnover	Interaction Factor	Savings in 2025 (GWh)
Existing Buildings												
HVAC												
Duct testing and sealing	HVAC	10	24,828	NA	0.53	$ 3,375	NA	$ 0.02	25%	100%	100%	352
Cool roof	HVAC	20	5,513	NA	0.16	$ 3,750	$ 0.25	$ 0.05	80%	85%	100%	289
Roof insulation	HVAC	20	NA	NA	0.28	NA	$ 0.12	$ 0.03	35%	100%	100%	257
Low-e windows	HVAC	25	NA	NA	0.26	NA	$ 0.07	$ 0.02	75%	68%	100%	358
Efficient ventilation fans & motors w VFD	HVAC	10	21,977	NA	0.26	$ 6,650	NA	$ 0.04	40%	100%	89%	249
Load-Reducing Measures Subtotal												**1,505**
High-effic. unitary AC & HP (65-135 kbtu)	HVAC	15	1,070	NA	0.31	$ 629	NA	$ 0.06	33%	100%	87%	237
High-effic. unitary AC & HP (135-240 kbtu)	HVAC	15	3,371	NA	0.47	$ 1,415	NA	$ 0.04	15%	100%	87%	161
Packaged Terminal HP and AC	HVAC	15	226	NA	0.34	$ 88	NA	$ 0.04	5%	100%	87%	39
Efficient room air conditioner	HVAC	9	112	NA	0.23	$ 30	NA	$ 0.04	4%	100%	87%	20
High-efficiency chiller system	HVAC	23	30,347	NA	0.87	$ 9,900	NA	$ 0.02	33%	74%	87%	487
HVAC Equipment Measures Subtotal	HVAC											**943**
Dual Enthalpy Control	HVAC	10	3,036	NA	0.51	$ 889	NA	$ 0.04	46%	100%	79%	480
Demand-Controlled Ventilation		15	8,000	NA	0.21	$ 3,450	NA	$ 0.04	54%	100%	79%	238
HVAC tuneup (smaller buildings)	HVAC	3	924	NA	0.37	$ 158	NA	$ 0.06	22%	100%	79%	172
Energy management system install	HVAC	15	23,200	NA	0.39	$ 6,380	NA	$ 0.03	33%	100%	79%	266
Retrocommissioning	HVAC	7	NA	NA	0.42	NA	$ 0.25	$ 0.04	43%	100%	79%	382
HVAC Control Measures Subtotal	HVAC											**1,536**
HVAC Subtotal												**3,986**
Water Heating												
Commercial clothes washers - 2.0 MEF	Water Heating	11	705	81,208	0.00	$ 316	NA	$ 0.04	14%	100%	100%	8
Heat pump water heater	Water Heating	12	14,155	NA	0.34	$ 4,067	NA	$ 0.03	24%	100%	99%	220
												228
Refrigeration												
Walk-in coolers & freezers	Refrigeration	12	8,220		0.56	$ 957	NA	$ 0.01	9%	100%	100%	134
Reach-in coolers & freezers	Refrigeration	9	1,268		0.40	$ 177	NA	$ 0.02	15%	100%	100%	165
Ice-makers	Refrigeration	10	542		0.21	$ 100	NA	$ 0.02	9%	100%	100%	51
Supermarket (built-up) refrigeration system	Refrigeration	10	336,000		0.27	$ 37,000	NA	$ 0.01	33%	100%	100%	233
Vending machines (to tier 2 Energy Star level)	Refrigeration	10	507		0.23	$ 30	NA	$ 0.01	13%	100%	100%	82

Measures	End-Use	Measure Life (Years)	Annual kWh svgs per unit	2007 Virginia Stock	kWh svgs per s.f.	Incremental cost per unit	Incremental cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjustment Factor	% Turnover	Interaction Factor	Savings in 2025 (GWh)
Vending miser	Refrigeration	10	808		0.37	$ 167	NA	$ 0.03	13%	100%	100%	131
												796
Lighting												
Fluorescent lighting improvements	Lighting	14	64	NA	1.99	$ 4	NA	$ 0.01	56%	100%	100%	2,947
HID lighting improvements	Lighting	2	447	NA	1.90	$ 60	NA	$ 0.06	12%	100%	100%	603
Replace incandescent lamps	Lighting	13	180	NA	5.04	$ (22)	NA	$ (0.01)	22%	100%	100%	2,990
Occupancy sensor for lighting	Lighting	10	361	NA	1.36	$ 48	NA	$ 0.02	38%	100%	66%	915
Daylight dimming system	Lighting	20	143	NA	2.54	$ 68	NA	$ 0.04	25%	85%	61%	878
Retrocommissioning	Lighting	7	NA	NA	0.71	NA	$ 0.25	$ 0.04	43%	100%	57%	459
Outdoor lighting -- controls	Lighting	14	174	2,218,811	NA	$ 43	NA	$ 0.03	30%	100%	74%	86
												8,878
Office Equipment												
Office equipment	Office Equip.	5	1,410	-	1.46	$ 0.02	$ 20	$ 0.003	50%	100%	100%	1,935
												1,935
Appliances/Other												
Hot Food Holding Cabinets	Appliances	15	1,815	10,515	NA	$ 453	NA	$ 0.02	25%	100%	100%	5
Commercial clothes washers - 2.0 MEF	Appliances	11	339	81,208	NA	$ 316	NA	$ 0.04	31%	100%	100%	9
												13
Existing Buildings Subtotal												**15,837**
New Buildings												
Efficient new building (15% savings)	ALL	17	NA	NA	1.99	NA	$ 0.35	$ 0.02	18%	100%	100%	241
Efficient new building (30% savings)	ALL	17	NA	NA	3.98	NA	$ 0.70	$ 0.02	35%	100%	100%	964
Tax credit eligible building (50% svgs)	ALL	17	NA	NA	6.64	NA	$ 3.00	$ 0.04	47%	100%	100%	2,143
												3,348
											TOTAL	**19,185**

C.3. Industrial Sector

C.3.1. Overview of Approach

The analysis of electricity savings potential was accomplished in several steps. First, the industrial market in Virginia was characterized at a disaggregated level and electricity consumption for key end-uses was estimated. Then cost effective energy-saving measures were selected based on the projected average retail industrial electricity price. The economic potential savings for these measures was estimated by applying the efficiency measures to electricity end-use consumption. The following sections described the process for estimating the savings potential in Virginia.

C.3.2. Market Characterization and Estimation of Base Year Electricity Consumption

The industrial sector is made up of a diverse group of economic entities spanning agriculture, mining, construction and manufacturing. Significant diversity exists within most of these industry sub-sectors, with the greatest diversity within manufacturing. The various product categories within manufacturing are classified using the North American Industrial Classification System (NAICS) (Census 2002).[4]

Comprehensive, highly-disaggregated electricity data for the industrial sector is not available at the state level. To estimate the electricity consumption, this study drew upon a number of resources, all using the NAICS system and a consistent sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base-year of 2002.

We then used national industry electricity intensities derived from industry group electricity consumption data reported in the *2002 Manufacturing Energy Consumption Survey* (MECS) (EIA 2005) and value of shipments data reported in the *2002 Annual Survey of Manufacturing* (ASM) (Census 2005) to apportion industrial electricity consumption. These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in Virginia. These electricity consumption estimates were then used to estimate the share of the industrial sector electricity consumption for each sub-sector.

<u>Preparation of Baseline Industrial Electricity Forecast</u>

As is the case for state-level energy consumption data, no state-by-state disaggregated electricity consumption forecasts are publicly available. Several alternate data sources were used to calculate estimated electricity consumption growth rates for each state and sub-sector. We made the assumption that electricity consumption will be a function of gross state value of shipments (VOS). Electricity consumption, however, will not grow at the same rate as value of shipments. This is because in general, energy intensity (energy consumed per value of output) decreases with time.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Moody’s Economy.com. The average growth rate for specific industrial-subsectors was estimated based on Economy.com’s estimates of gross state product. We used this estimated industrial electric consumption distribution to apportion the EIA estimate (2005) of industrial electricity consumption.

Twelve manufacturing sub-sectors, along with agriculture, mining, and construction, were chosen to represent industrial electricity use in Virginia (Table C.5). The manufacturing (NAICS 31-33) sub-sectors include beverage & tobacco products, transportation equipment, food, chemicals, plastics & rubber, computer and electronic products, paper, fabricated metal products, textile mills, wood products, machinery, and printing & related support activities. In order to simplify the analysis and to obtain information that would be of greatest significance to the state, only sub-sectors with value of

[4] The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. Each sub-sector is further broken down into individual industry groups reflecting the many different definitions for the term ‘industrial.’

shipments greater than 3% of total Virginia's industrial sector were included. In order to provide more insight and to match available data, two manufacturing sub-sectors were further analyzed. Beverage and tobacco manufacturing was broken down to separate beverage manufacturing and tobacco manufacturing, and chemical manufacturing was broken down into pharmaceuticals manufacturing and all other chemical manufacturing. These fifteen industrial sub-sectors account for almost 90% of Virginia's total industrial value of product shipments.

Table C.5. Base-Case Electricity Consumption by Industry in Virginia (Calibrated to 2002 Electric Power Annual)

NAICS Code	Industry Name	Base-Case Electricity Consumption (M kWh)	Percent of Total Industrial Consumption
11-13	Agriculture	555	2.8%
21	Mining	809	4.1%
23	Construction	1,141	5.8%
312	Beverage & tobacco product mfg	1,915	9.7%
3121	*Beverage*	*957*	
3122	*Tobacco*	*957*	
336	Transportation equipment mfg	1,098	5.5%
311	Food mfg	1,146	5.8%
325	Chemical mfg	5,264	26.6%
3254	*Pharmaceutical & medicine mfg*	*2,053*	
325x	*All other chemical products*	*3,211*	
326	Plastics & rubber products mfg	1,069	5.4%
334	Computer & electronic product mfg	733	3.7%
322	Paper mfg	1,375	6.9%
332	Fabricated metal product mfg	305	1.5%
313	Textile mills	543	2.7%
321	Wood product mfg	538	2.7%
333	Machinery mfg	267	1.3%
323	Printing & related support activities	430	2.2%
	Other Manufacturing	2,628	13.3%
Total Industrial Consumption		19,814	

<u>Market Characterization Results</u>

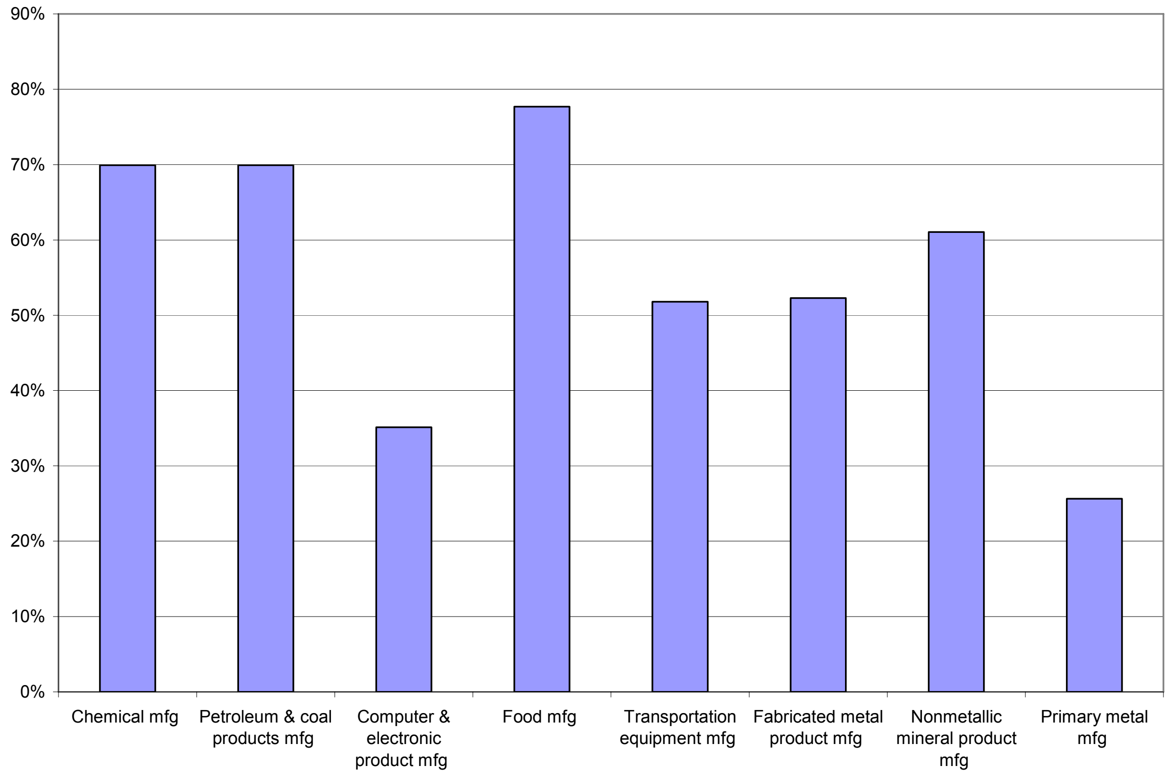
In 2008, the State of Virginia industrial sector consumed 19,814 GWh of electricity. Within the manufacturing sector, chemical manufacturing (NAICS 325) was the single largest electricity user with 26.6% of the electricity use, followed by beverage and tobacco products (NAICS 312) with 9.7% of industrial electricity use.

C.3.3. Industrial Electricity End Uses

In order to determine the electricity savings for any technology, the fraction of the electricity to which the technology is applicable must be determined. Much of the energy consumed by industry is directly involved in processes required to produce various products. Electricity accounts for about a third of the primary energy used by industries (EIA 2005). Electricity is used for many purposes, the most important being to run motors, provide lighting, provide heating, and to drive electrochemical processes.

While detailed end-use data is only available for each manufacturing sub-sector and group through the MECS survey (EIA 2005), motor systems are estimated to consume 60% of the industrial electricity (Xenergy 1998). The fraction of total electricity attributed to motors is presented in Figure C.6.

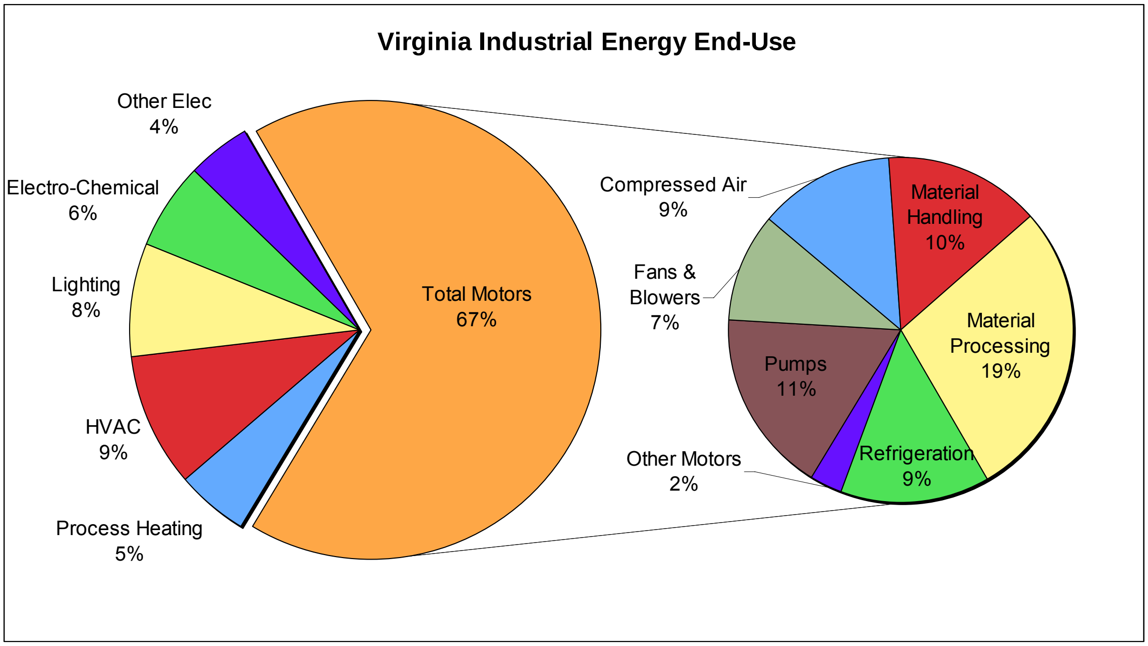
Figure C.6. Percent of Total Electricity Consumption by Motor Systems



Source: XENERGY (1998)

Motors are used for many diverse applications from fluid applications (pumps, fans, and air and refrigeration compressors), to materials handling and processing (conveyors, machine tools and other processing equipment). The distribution of these motor uses varies significantly by industry, with material processing being the largest consumer in the sector. Figure C.7 shows the total weighted average of end-use electricity consumption in Virginia with a breakdown of motors use in the state.

Figure C.7. Weighted Average of Total Industrial Electricity End-Uses in Virginia with Breakdown of Industrial Motor System End-Uses



While lighting and space conditioning represent a relatively small share of the overall industrial sector electricity consumption, they are important in some of the key industries found in the region such as transportation equipment manufacture and computer and electronics manufacturing, and the electricity savings potential can be significant.

C.3.4. Overview of Efficiency Measures Analyzed

The first step in our technology assessment was to collect limited information on a broad “universe” of potential technologies. Our key sources of information included the U.S. Department of Energy, Office of Industrial Technologies; the Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET); Lawrence Berkeley National Laboratory (LBNL) and American Council for an Energy-Efficient Economy reports; and information from NYSERDA. We did not collect any primary data on technology performance.

Oftentimes, no one source provided all of the information we sought for our assessment (energy use, energy savings compared to average current technology, investment cost, operating cost savings, lifetime, etc.). We therefore made our best effort to combine readily available information along with expert judgment where necessary.

We identified 14 measures that were cost effective at the average projected industrial electricity rates in Virginia of $0.07/kWh (Table C.6). The cost and performance of these measures has been developed over the past decade by ACEEE from research into the individual measures and review of past project performance. The costs of many of these measures has increased in recent years as a result of significant increases in key commodity costs such as copper, steel and aluminum, as well as overall manufacturing costs due to energy prices and market pressures. The estimates presented in Table C.6 represent ACEEE most current estimates. We present the full normalized installed measure cost (i.e., the full cost required to install a measure per unit of saved energy) as well as the levelized cost (i.e., the annual cost of the measure amortized over the life of the measure).

Table C.6 Cost and Performance of Industrial Measures

		Cost of Saved Energy		
Measure	Measure Life	Installed Cost/kWh	Levelized cost/kWh	Annual Savings for End-Use
Sensors & Controls	15	0.145	0.014	3%
EIS	15	0.635	0.061	1%
Duct/Pipe insulation	20	0.653	0.052	20%
Electric supply	15	0.104	0.010	3%
Lighting	15	0.212	0.020	23%
Advanced efficient motors	25	0.491	0.035	6%
Motor management	5	0.079	0.018	1%
Lubricants	1	0.000	0.000	3%
Motor system optimization	15	0.097	0.009	1%
Compressed air manage	1	0.000	0.000	17%
Compressed air - advanced	15	0.001	0.000	4%
Pumps	15	0.083	0.008	20%
Fans	15	0.249	0.024	6%
Refrigeration	15	0.034	0.003	10%

In addition, we estimated the average normalized cost of industrial energy efficiency investments to be $0.29/kWh saved. This estimate was arrived at by estimating the sum of the annual incremental savings for each measure in each industry based on end-use energy distribution and dividing the corresponding total investment required.

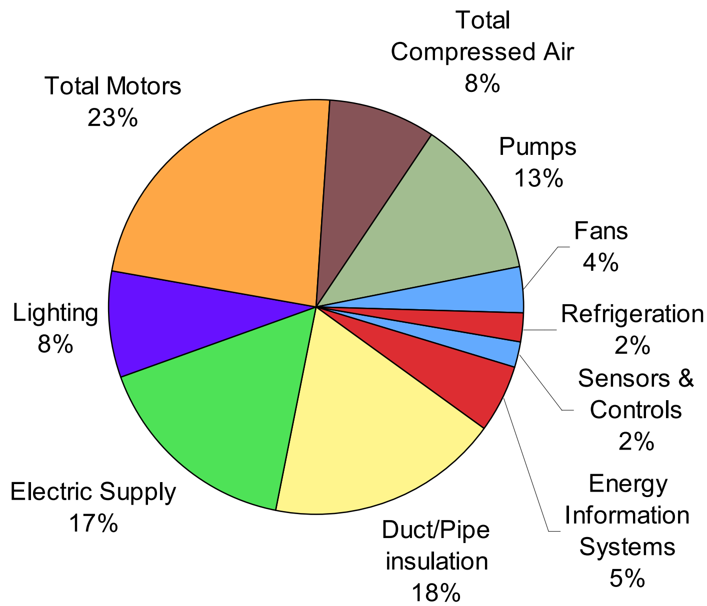
C.3.5. Electricity Savings Potential: Potential for Energy Savings

We sought to identify technologies that could have a large potential impact in terms of saving energy. These may be technologies that are specific to one process or one industry sector, or so-called "cross-cutting" technologies that are applicable to a variety of sectors. In estimating energy savings, we first identified the specific energy savings of each technology by comparing the energy used by the efficient technology to the energy required by current processes. Our second step was to "scale up" this savings estimate to see how much energy savings—for industry overall—this technology would achieve. For the most part, we derived specific energy savings information from the various technology assessment studies noted above.

In scaling up the technology-specific energy savings, we relied on our general knowledge of the various industrial processes to which this technology could be applied. We also took into account structural limitations to the penetration of the technology. Additionally, we recognized that market penetration, in the absence of significant policy support, can take time given the slowness of stock turnover in many industrial facilities.

In Virginia, a diverse set of efficiency measures will provide electricity savings for industry. The application of these measures contributes to total economic savings potential of 18%. These savings are distributed as presented in Figure C.9.

Figure C.9. Fraction of Savings Potential by Measure - Virginia



In addition, this analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available data does not allow this level of analysis. However, based on experience from site assessments by U.S. Department of Energy and others entities, we would anticipate an additional economic savings of 5-10%, primarily at large energy intensive manufacturing facilities. Therefore, the overall economic industrial efficiency resource opportunity is on the order of 23-28%.

Appendix D - Demand Response Analysis

D.1.Introduction

This report defines Demand Response (DR), assesses current DR activities in Virginia, identifies policies in the commonwealth that impact DR, uses benchmark information to assess DR potential in Virginia, and identifies barriers in the commonwealth that might keep DR contributing appropriately to the resource mix that can be used to meet electricity needs. The analysis concludes with identification of policy recommendations regarding DR.

D.1.1. Objectives of this Assessment

This assessment develops estimates of DR potential for Virginia. Potential load reductions from DR are estimated for the residential, commercial, and industrial sectors (see Section 3). The assessment also includes discussions of reductions possible from other DR programs, such as DR rate designs (see Section 3.6).

D.1.2. Role of Demand Response in Virginia's Resource Portfolio

The DR capabilities developed by Virginia utilities will become part of a long-term resource strategy that includes resources such as traditional generation resources, renewable energy, power purchase agreements, options for fuel and capacity, energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Virginia customers to better manage their electricity costs. The growth of renewable energy supply (and plans for increased growth) can increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

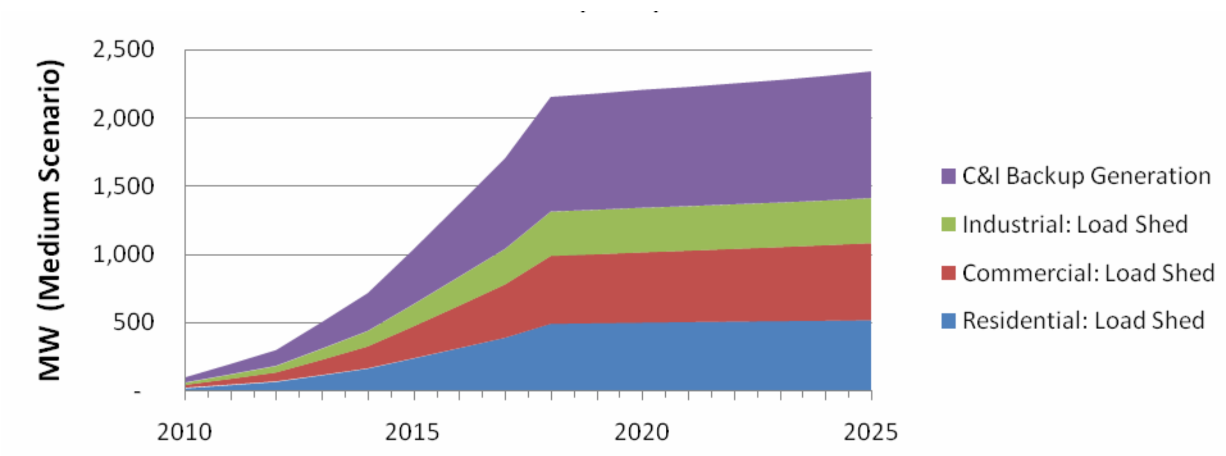
D.1.3. Summary of DR Potential Estimates in Virginia

Table D-1 shows the resulting load shed reductions possible for Virginia, by sector. The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities. The high scenario results show a reduction in peak demand of 1,566 MW (5.4% of 2015 peak demand) is possible by 2015; 3,332 MW (10.8% of 2020 peak demand) is possible by 2020; and 3,537 MW (10.8% of 2025 peak demand) is possible by 2025. The more conservative medium scenario results show a reduction in peak demand of 1,038 MW (3.6% of 2015 peak demand) is possible by 2015; 2,209 MW (7.2% of 2020 peak demand) is possible by 2020; and 2,345 MW (7.2% of 2025 peak demand) is possible by 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

Table D-1. Summary of Potential DR in Virginia, By Sector, for Years 2015, 2020, and 2025[a]									
	Low Scenario			**Medium Scenario**			**High Scenario**		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Residential (MW)	143	299	310	238	499	516	333	699	723
Commercial: Load Shed (MW)	88	194	213	235	517	567	441	970	1,063
Industrial: Load Shed (MW)	72	145	147	162	327	331	289	582	588
C&I Backup Generation (MW)	302	639	698	402	865	930	503	1,082	1,163
Total DR Potential (MW)	605	1,288	1,367	1,038	2,209	2,345	1,566	3,332	3,537
DR Potential as % of Total Peak Demand (30,065 MW)	2.1%	4.2%	4.2%	3.6%	7.2%	7.2%	5.4%	10.8%	10.8%
a. See Section 3 for underlying data and assumptions.									

Figure 1 shows the resulting load shed reductions possible for Virginia, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-1. Potential DR Load Reductions in Virginia by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates are based on assumptions regarding growth rates, participation rates, and program design. These factors are discussed in Chapter 3. In developing these DR potential estimates, the integration of DR with select energy efficiency activities was considered to help ensure that load impacts were not double counted. The estimated load reduction per program participant is conservatively estimated to account for increased energy efficiency in the future.

D.2.Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions, and it can enhance operating reserves available to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR is an increasingly important tool for resource planning as power plant siting has grown more difficult and the costs of peak power have increased. Through development of DR capability, utilities can complement existing energy efficiency programs with a set of offerings that provide, at a minimum, 1) enhanced reliability, 2) cost savings, 3) reduced operating risk through resource diversification, and 4) increased opportunities for customers to manage their electric bills.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can “call” for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and investment in overall electric infrastructure is needed to support new generation resources.

The mechanisms that utilities may use to achieve load reductions can range from voluntary curtailments to mandatory interruptions. These mechanisms include, but are not limited to:

- Direct load control by the utility using radio frequency or other communications platforms to trigger load devices connected to air conditioners, electric water heaters, and pool pumps;
- Manual load curtailments at commercial and industrial (C&I) facilities, including shutting off production lines and dimming overhead lighting;
- Automated DR (“Auto-DR”) technologies utilizing controls or energy management systems to reduce major C&I loads in a pre-determined manner (e.g., raising temperature set points and reducing lighting loads); and
- Behavior modifications such as raising thermostat set points, deferring electric clothes drying in homes, and reducing lighting loads in commercial facilities.

D.3.Rationale for Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability—**DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.

- **Reduce supply costs—**DR may be a less expensive option per megawatt than other resource alternatives. DR resources compete directly with supply-side resources in many regions of the country. Portfolios that help lower the increase in customers' expenditures on electricity over time represent an increasingly important attribute from the perspective of many energy customers.

- **Manage operational and economic risk through portfolio diversification—**DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.

- **Provide customers with greater control over electric bills—**DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events. The ability to manage increases in energy costs has increased in importance for both residential and commercial customers. Standard residential and commercial tariffs provide customers with relatively few opportunities to manage their bills.

- **Address legislative/regulatory interest in DR—**Electric utility legislation enacted in April 2007 set a statutory goal for the commonwealth to save 10% of Virginia's total 2006 electricity sales by 2022 (H.B. 3068 and S.B. 1416, commonly referred to as electricity "re-regulation" legislation). This goal is estimated to total about 11 billion kWh, based on federal Energy Information Administration data for the 2006 base year (VCSS 2008). While the legislation focuses on an energy consumption goal, the Virginia State Corporation Commission Energy Efficiency Working Group has stated that reducing peak demand is also an important consideration (SCC 2008c).

DR is gaining greater acceptance among both utilities and regulators in the United States. A 2006 FERC survey found that 234 "entities" were offering direct load control programs and the FERC's assessment noted that "there has been a recent upsurge in interest and activity in DR nationally and, in particular, regional markets" (FERC 2006).[5] The recent proliferation of DR offerings has been promoted in part by utilities hoping to reduce system peaks while offering customers more control over electric bills and in part by regulators. Although federal legislation has not been the driver behind the trend, it is one of many indications, at all levels of government and industry, of the growing support for DR.[6]

Many states experience significant reductions in peak demand from Demand-Side Management (DSM) programs (which include DR programs). Regulatory filings show that California experienced 495 MW in peak demand reductions in 2005 (1% of total peak demand); New York experienced 288 MW reductions in 2005 (1% of total peak demand); and Texas experienced 181 MW in reductions in 2005 (1% of total peak demand) from DSM programs. These results are annual values that do not consider the cumulative (i.e., year-to-year) impacts that accrue over the lifetimes of the conservation measures. Therefore, cumulative percentage reductions in peak demand are much higher than the annual figures stated.

D.4.Assessment Methods

As has been shown in numerous other jurisdictions across North America, well-designed DSM programs incorporating DR strategies represent an effective and affordable option for reducing peak demand and meeting growing demand for electricity. This effort estimated conservative peak demand reduction for Virginia using local energy use characteristics, demographics, and forecast peak demand, assuming relatively basic DR strategies comprising responsive reductions in demand. The following research approach was used to conduct the analysis:

- Review of existing information regarding Virginia's customer base including:
    - Customer counts and average annual energy consumption by market segment;
    - Forecasts of future energy consumption and customer counts by market segment;
    - Previous DSM planning and potential studies.
- Review of additional publicly-available secondary sources including:

[5] The FERC report uses the term "entities" to refer to all types of electric utilities, as well as organizations such as power marketers and curtailment service providers.
[6] The federal Energy Policy Act of 2005 (EPAct) directs the Secretary of Energy to "identify and address barriers to the adoption of demand response programs," and the Act declares a U.S. policy in support of "State energy policies to provide reliable and affordable demand response services." EPAct directed FERC to conduct its survey of DR programs and also directed the U.S. Department of Energy to report on the benefits of DR and how to achieve them (DOE, 2006). Separately, a *National Action Plan for Energy Efficiency,* which advocates DR and other efficiency efforts, was developed by more than 50 U.S. companies, government bodies, and other organizations, including co-chairs Diane Munns, President of NARUC and Jim Rogers, President and CEO of Duke Energy (U.S. Environmental Protection Agency, 2006). Other utility industry members of the Leadership Group included Southern Company, AEP, PG&E, TVA, PJM Interconnection, ISO New England, and the California Energy Commission.

    - U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) and Residential Energy Consumption Survey (RECS) data;
    - Previous studies relevant to the current effort completed by Summit Blue in other regions as well as entities in other jurisdictions.
- Development of baseline profiles for residential and commercial customers. These profiles include current and forecast numbers of customers by market segment and electricity use profiles by segment.
- Incorporation of ACEEE baseline data and reference case into analysis.
- Obtaining state-level data when possible and estimation of information for the Commonwealth of Virginia, when state-level data was not available.
- Development of a spreadsheet approach for estimating peak demand reduction potential associated with the DR programs/technologies deemed to be most applicable to Virginia. Estimates are developed for three scenarios—low, medium and high case scenarios.
- Conference calls with ACEEE staff and industry professionals to discuss assessment processes and legislative, regulatory, and other factors specific to the Commonwealth of Virginia.
- Incorporation of all sources of information and references into report, noting on each figure the source of the information.
- Revision of draft report based on comments from ACEEE, industry specialists and utility commenters.

The DR potential estimated used historical data and experience to obtain curtailment levels. This potential is assumed to be the achievable potential that would be cost effective, given the range of incentives that are typically required and the range of the utilities' avoided costs. A cost-effectiveness analysis was not performed for this study. Sufficient incentives could be provided to customers to encourage load reductions while maintaining a cost-effective program given avoided costs in the range of $70-$75 per kW (based on the analysis reference case).

Commonwealth of Virginia - Background

A sound strategy for development of DR resources requires an understanding of Virginia's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

VA utilities serve more than three million residential facilities and more than 390,000 non-residential facilities, providing power that is expected to have a system peak load of close to 24,000 MW in 2008. The service territory is characterized by high population and load growth, the majority of which is attributable to new residents. Since 2000 the commonwealth has grown in population by 8%, compared to 6% for the United States as a whole. The impact of population growth on electricity demand is compounded by the fact that *electricity consumption per customer* has risen significantly in the past several decades.

All of Virginia is located with the PJM regional transmission organization, the largest power region in the US with installed capacity of over 164,000 MW. PJM covers 11 states including Pennsylvania, New Jersey, Maryland, Delaware, Virginia, West Virginia and parts of Ohio, Indiana, Illinois, Michigan and North Carolina. See Section 2.2 for a discussion of PJM's DR programs.

Dominion Virginia Power (Dominion) is the largest utility in Virginia, supplying over 90% of total new generation for the Commonwealth (EIA 2006a). Demand is growing faster in Dominion's Virginia service territory than anywhere else in the 13 states served by PJM (Dominion 2008b).

PJM projects that the peak demand for electricity in Dominion's service area will grow by almost 1,800 megawatts in just five years—the equivalent, in PJM's estimation, of adding one million homes to the system. Dominion's own studies project it will need 4000 MW of new capacity in ten years. This growth will impose severe strains on Virginia's electric system (Dominion 2008b).

D.4.1. Assessment of Utility DR Activities

Virginia has had some of the lowest electricity rates in the county and, until recent years, has had adequate capacity to meet the Commonwealth's electricity needs. As a result, interest in energy efficiency and DR in Virginia has been limited in past years. Current conditions are changing. Capacity is being strained and electricity costs are increasing. Rising electricity costs stem from a combination of rising consumption, necessitating new investment in generation and transmission, increases in fuel costs, and the potential for additional environmental restrictions. The elimination of price caps and potentially higher fuel prices will increase the importance in assessing future resources and DR potential.

Utility-specific information on DR participation in Virginia is not readily available. The Appalachian Power Company (APCO) stated that they have not determined the DR from residential and small commercial customer programs, but do have a prevalence of 70.9 MW of distributed generation, and the participation of one large industrial customer on a real-time pricing type rate with approximately 11MW subject to interruption (APCO 2008). The Company has not quantified other industrial DR levels, but customers are provided time-of-day demand rates and shift load to take advantage of off-peak demand rates.

Dominion has stated that in June of 2008, they introduced an aggressive energy conservation and demand reduction plan that it intends to offer Virginia customers, subject to Commission approval. The plan includes DR programs such as residential AC and heat pump cycling and incentives for commercial customers who install back-up generators available for dispatch during peak demand periods (Dominion 2008a).

The PJM Interconnection (PJM), a regional transmission organization (RTO) containing the entire commonwealth of Virginia, provides opportunities for DR to realize value for demand reductions in the Energy, Capacity, Synchronized Reserve, and Regulation markets. The FERC authorized PJM to provide these opportunities as permanent features of these markets in early 2006 (PJM 2008a).

The PJM Economic Load Response Program enables customers to voluntarily respond to PJM Locational Marginal Price ("LMP") prices by reducing consumption and receiving a payment for the reduction. The growth of participation by end-use customers since 2002 is significant, with over 225,000 MWh of participation in 2006 (PJM 2008a). PJM's Load Response Activity Report of July 2008 reported 50 sites in their Economic Program in Virginia, including 237.4 MW (PJM 2008c). The report also states 190 sites and 176.7 MW are included in their Emergency ILR and DR programs.

Under the Reliability Pricing Model (RPM), customers can offer DR as a forward capacity resource. DR providers can submit offers to provide a demand reduction as a capacity resource in the forward RPM auctions. In the first annual RPM auction which was held in April 2007 for the 2007/2008 planning period, 127.6 MW of demand response offers were cleared (PJM 2008a).[7]

[7] It is not known what portion of PJM DR reductions have been fulfilled by Virginia customers. [NOTE: These data are forthcoming, but it is not expected that Virginia currently provides larger contributions to this PJM DR resource. For this analysis, 250 MW of demand response was assumed to be currently available in Virginia. The DR potential ramp rate numbers in the figures start at 250 MW to recognize what is believed to be a reasonable estimate of existing DR.

PJM held a symposium on DR in May, 2007 that was attended by a broad mix of stakeholders and subject matter experts. One of the most prominent themes to emerge from the symposium was the need for coordination between retail and wholesale markets in order to increase DR participation in PJM's markets. The participants at the PJM Symposium on DR identified priority opportunities, which formed the basis of a "Demand Response Roadmap" to guide action (PJM 2008b).

D.4.2. Assessment of Current Commonwealth Policies Affecting DR

Electric utility legislation enacted in April 2007 (H.B. 3068 and S.B. 1416, commonly referred to as electricity "re-regulation" legislation) set a statutory goal for the commonwealth to save 10% of Virginia's total 2006 electricity sales by 2022. The legislative language is as follows:

> The Commonwealth shall have a stated goal of reducing the consumption of electric energy by retail customers through the implementation of such programs by the year 2022 by an amount equal to ten percent of the amount of electric energy consumed by retail customers in 2006.
>
> The State Corporation Commission shall conduct a proceeding to determine whether the ten percent electric energy consumption reduction goal can be achieved cost-effectively through the operation of such programs, and if not, determine the appropriate goal for the year 2022 relative to base year of 2006,
>
> In developing a plan to meet the goal, the Commission may consider providing for a public benefit fund and shall consider the fair and reasonable allocation by customer class of the incremental costs of meeting the goal. This goal is estimated to total about 11 billion kWh, based on federal Energy information Administration data for the 2006 base year.

Reservations about DSM that the Virginia State Corporation Commission (SCC) may have had under the price-capped transition to retail competition are not likely continue since that transition has been abandoned in the new "re-regulation" bill. In particular, the bill:

- Provides incentives for utilities to find renewable forms of energy and establish demand-side management and conservation programs;
  Allows each utility to seek rate adjustment clauses to recover costs of FERC-approved demand response programs and costs of providing incentives for the utility to design and implement demand-side management programs; and
- Directs the SCC to "conduct a proceeding to establish goals for the amount of energy and demand to be reduced by the operation of demand-side management, conservation, energy efficiency, and load management programs, and develop a plan for the development and implementation of recommended programs."

More recently Governor Kaine issued Executive Order 48 that directs the Commonwealth's executive Branch to reduce the annual cost of energy purchases from non-renewable sources by at least 20% by fiscal year 2010. These initiatives provide the Commonwealth with an opportunity to integrate cost-effective demand- and supply-side options into system planning processes. This directive could create business opportunities for independent vendors of DSM programs and technologies.

The SCC was directed by the General Assembly to conduct a proceeding and submit its findings and recommendations for any additional legislation necessary to implement the plan to meet the energy consumption reduction goal. The SCC's sub-group 3 claimed that "new opportunities exist to capture the potential for reductions in peak demand resulting from recent policy enhancements within the PJM Interconnection, advances in telecommunications allowing real-time communication, and improvements in the affordability and functionality of DR technology. This sub-group found that increased deployment of DR in the Commonwealth could yield substantial customer financial benefits and electric reliability benefits. Historically, the focus on the utility industry in Virginia, as in most jurisdictions, has been on supply-side, rather than demand-side, solutions to address peak demand. As a result, generating plants and transmission lines have been and continue to be relied upon to meet peak loads during the limited hours of the year in which these loads occur… Staff believes that it is advisable for Virginia's electric utilities to develop a current integrated resource plan that considers supply and demand resources for the Commonwealth and to thus determine the value of avoided electrical supply costs" (SCC 2007).

Sub-group 3 identified institutional and infrastructure barriers to DR, including:

- Fragmentation in the industry and government regulatory oversight.
- Lack of customer education.
- Lack of clarity and coordination between the Federal and State agencies and programs.
- Lack of standards.
- Lack of consideration of societal benefits, including environmental benefits of most forms of DR.
- Difficulty in navigating DEQ requirement, making it hard for users to utilize customer owned, otherwise idle, generation capability (SCC 2007).

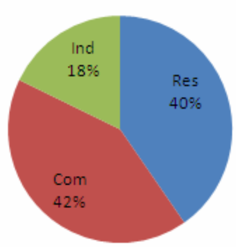
The sub-group developed a list of recommendations to address these barriers, and to reduce other existing impediments to DR programs including:

- Lack of perceived need for DR;
- Incentives and cost recovery;
- Fragmentation in the industry and government regulatory oversight;
- Concern about the potential economic and operational impact of DR on industrial customers; and
- Rate design (SCC 2007).

D.4.3. Energy and Peak Demands

Use of energy in Virginia is distributed to end use categories as follows: 42% commercial, 40% residential, and 18% industrial sectors (see Figure 2).

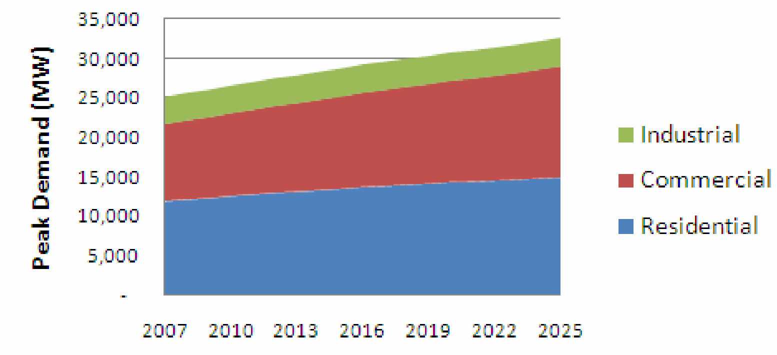
Figure D-2. Energy Sales in Virginia by Sector (2006)



Source: EIA (2006a)

In 2007, the total summer peak load was 25,200MW and is projected to grow an average of 1.46% per year through 2025. Figure 3 displays peak demand by sector. In 2007, residential peak demand was 11,892MW (47%); commercial was 9,791MW (39%); and industrial was 3,522MW (14%).

Figure D-3. Peak Demand by Sector in Virginia (MW)



Source: ACEEE Reference Case for Virginia

Air conditioning (AC) makes up the largest portion of peak demand needs in many states, primarily in southern states. For one utility in Florida, a confidential study revealed that in 2005, AC accounted for 67% of residential peak demand for single-family homes, and 62% for multi-family homes. For commercial and industrial peak demand, data from the California Commercial End-Use Survey 2005 shows that AC accounted for between 50 to 60 percent of peak demand for the following categories:

- College (59%)
- Health Care (58%)
- Large Office (56%)
- Hotel (53%)
- Small Office (51%)

AC use in warehouses only accounted for approximately 13% of peak demand, with lighting accounting for 50% and "other" accounting for 38%.

D.4.4. Smart Grids and Advanced Metering Infrastructure (AMI)

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI).

Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. The end user is equipped with real-time communication between the consumer and utility allowing optimization of a consumer's energy usage based on environmental and/or price preferences (for example, critical peak pricing and time of use rates).

AMI provides:

- Two-way communication between the utility and the customer through the customer's smart meter.
- More efficient management of customer outages (location, re-routing).
- More accurate meter reading (minute, 15 minute intervals).
- More timely collection efforts (real time).
- Improved efficiency in handling service orders.
- More detailed, timely information about energy use to help customers make informed energy decisions (real time).
- Ability to reduce peak demand.
- More innovative rate options and tools for customers to manage their bills.

Smart Energy Pricing provides:

- Incentives to customers to shift energy away from critical peak periods
- The ability to for customers to save on their electricity bills.
- Lower wholesale prices for capacity and transmission—in the longer term.
- Improved electric system reliability, as demand is moderated.
- Potential to defer new transmission and generation.

The Smart Grid is comprised of multiple communication systems and equipment, which interoperability is crucial. Not all communication protocols are applicable to every utility's geography; therefore, pilots are essential in testing the equipment and communication software for various geographies. Furthermore, the identification of those geographic regions with the best return on investment during a pilot will aid the staged implementation plan. Standards are continuing to be researched through organizations including: 1) IntelliGrid—Created by the Electric Power Research Institute (EPRI); 2) Modern Grid Initiative (MGI) is a collaborative effort between the U.S. Department of Energy (DOE), the National Energy Technology Laboratory (NETL), utilities, consumers, researchers, and other grid stakeholders; 3) Grid 2030—Grid 2030 is a joint vision statement for the U.S. electrical system developed by the electric utility industry, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories; 4) GridWise—a DOE Office of Electricity Delivery and Energy Reliability (OE) program; 5) GridWise Architecture Council (GWAC) was formed by the U.S. Department of Energy; and 6) GridWorks—A DOE OE program.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion is deploying a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods.

These developments in technology allowing real time signaling and automated response will improve DR capabilities. However, existing technology exists for successful DR implementation and it is important to point out that there are no technology obstacles to effective DR.

D.5.Assessment of DR Potential in Virginia

This section examines and quantifies DR potential in Virginia. Section 3.1 outlines the general DR program categories, while Sections 3.2 and 3.3 outline the DR potential in the residential and commercial /industrial sectors, respectively. Section 3.4 discusses the load reduction potential from backup generation and Section 3.5 explains the issues surrounding rate pricing, even though benefits from this form of DR are not quantified in this analysis. Section 3.6 concludes with a summary of DR potential in Virginia.

D.5.1. Demand Response Program Categories

For the purposes of assessing DR alternatives, the following programs could be employed in Virginia to achieve the DR potential we outlined in this report:

Resource Category	Characteristics
Direct Load Control (DLC)	Direct load control (DLC) programs have typically been mass-market programs directed at residential and small commercial (<100 kW peak demand) air conditioning and other appliances. However, an emerging trend is to target commercial buildings with what has become known as Automated Demand Response or Auto-DR. Increased use and functionality of energy management systems at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in automated commercial curtailment in response to a utility signal. The common factor in these programs is that they are actuated directly by the utility and require the installation of control and communications infrastructure to facilitate the control process.
Callable Customer Load Response	With this type of program, utilities offer customers incentives to reduce their electric demand for specified periods of time when notified by the utility. These programs include curtailable and interruptible rate programs and demand bidding/buyback programs. Curtailable and interruptible rate programs can be used as “emergency demand response” if the advanced notice requirements are short enough. All customer load response programs require communications protocols to notify customers and appropriate metering to assess customer response.
Scheduled Load Control	This is a class of programs where customers schedule load reductions at pre-determined times and in pre-determined amounts. A variant on this theme is thermal energy storage which employs fixed asset technology to reduce air conditioning loads consistently during peak afternoon load periods.
Time-differentiated Rates	Pricing programs can employ rates that vary over time to encourage customers to reduce their demand for electricity in response to economic signals—in some cases these load reductions can be automated when a price trigger is exceeded. An example is a critical peak price which is “called” by the utility or system operator. In response to this critical price, residential customers can have AC cycling or temperature setbacks automatically deployed. Similar automated responses can be deployed by commercial customers. These rate programs are not analyzed for this assessment, but are further discussed in Section 3.5.

D.5.2. DR for Residential Customers

Air conditioner and other appliance direct load control (DLC) is the most common form of non-price-based DR program in terms of the number of utilities using it and the number of customers enrolled. According to FERC’s 2006 assessment of DR and advanced metering, there are 234 utilities (including municipalities, cooperatives, and related entities) with DLC programs across the United States. Approximately 4.8 million customers are participating in DLC programs across the country (FERC 2006).

The prominent and growing role of air conditioning in creating system peaks makes it a high-profile candidate for DR efforts. The advances in DR technology that make AC load management economically viable make AC load control a high-priority program—one that has been proven reliable and effective at many utilities. Pool pumps are also a relatively easy and non-disruptive load that can be controlled for DR purposes.

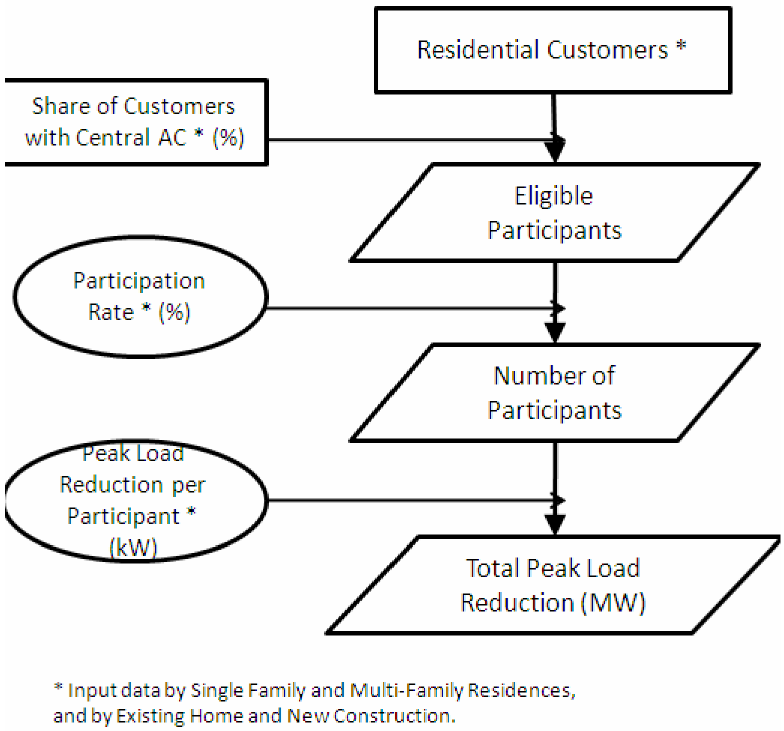
<u>Residential Control Strategies</u>

There are two basic types of control strategies: AC cycling and temperature offset. AC cycling limits ACs being on to a certain number of minutes than they otherwise would have been on. Some techniques limit ACs to being on for 50% of the minutes they would otherwise have been on. A temperature offset increases the thermostat setting for a certain period of time, for a certain number of degrees higher than it would have otherwise been set. This essentially causes the AC compressor to cycle as the temperature set-back reduces the AC demand. Sequential thermostat setbacks, i.e., one degree in a hour one, two degrees in hour two, three degrees in hour three, and four degrees in hour four can mimic an AC cycling strategy.

Cycling strategies have evolved where an optimal impact on peak kW demand may be obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Progress Energy Carolinas (PEC) and in PSE&G's MyPower pilot program. This type of strategy requires that forecasters accurately predict the hour(s) in which the peak system demand will occur.

<u>Assessment of DR Potential in Residential Homes in Virginia</u>
For Virginia, estimates for possible load reductions for residential housing units were obtained by applying the methodology displayed in Figure 4.

Figure D-4. Residential Peak Load Reduction



The figure shows how load reductions and participations rates are applied to housing data. Items listed in rectangular shapes are factual inputs; items in circular shapes are assumptions; and items in parallelogram shapes are results.

D.5.3. Load Reductions

Recent surveys show that DLC programs are being implemented by a number of utilities. Load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table D-2 shows the average reported kW impact based on 20 load control impact studies for programs based on the duty cycle used. These results support the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer, which is the impact used in this analysis. However, many homes will experience an impact greater than I kW, especially newer homes.

Table D-2. Average Load Impacts by Cycling Strategy for AC DLC Programs

Cycling Strategy	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue 2007b

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts were 60% of single-family, and thus a 0.6kW load reduction is applied in this analysis for multi-family units (Summit Blue 2007b).

<u>Eligible Residential Customers</u>

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. Residential accounts without central AC are assumed to have no participation.

Multi-family housing units often have building tenants which are not the account holders, therefore accounts are often aggregated into buildings. Some accounts have a master meter for the entire building, including tenants. Some accounts are for the “common” building loads (i.e., those loads that are part of a building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts.

The analysis assumes 70% of single-family residences have central AC. This is considered a conservative estimate for Virginia, as Progress Carolinas experience 77%. Arizona residences experience 95%, but have higher average temperatures than Virginia. Multi-family units typically have fewer units with central AC than single family. The analysis assumes 63% of multi-family residences have central AC, as 63% was obtained for all housing units obtained from 2005 RECS data from the EIA, averaging the data between the South and Middle Atlantic Census Regions.

<u>Residential Participation Rates</u>

Participation rates experienced in AC DLC programs vary across utilities typically from 7% of eligible customers to 40%, depending upon the effort made in maintaining and marketing the program (Summit Blue 2007a). The utilities with the low levels of participation had essentially stopped marketing the program in recent years. Utilities with programs with sustained attention to customer retention or recruitment show higher participation rates than utilities with one-time or intermittent promotion. In Maryland, BG&E's Demand Response Service program anticipates a residential participation rate of 50%, or approximately 450,000 controlled units (BGE 2007). The pilot phase of this program was conducted from June 1 through September 30, 2007, and 58% received a "smart" load control switch, and 42% had a "smart" thermostat installed (BGE 2007). One study examined 15 AC DLC programs nationwide and found an average of 24% participation for eligible customers (Summit Blue 2008a).[8] For this analysis, 3 typical yet conservative scenarios were used: a low scenario of 15% for eligible customers; a medium scenario of 25%; and a high scenario of 35%.

Results

Table D-3 displays the input data and results. In summary, the results for residential programs are as follows:

- A medium scenario reduction of 238 MW is possible by 2015, and 499 MW by 2020;
- A low scenario reduction of 143 MW is possible by 2015, and 299 MW by 2020;
- A high scenario reduction of 333 MW is possible by 2015, and 699 MW by 2020.

Table D-3. Potential Load Reduction from AC-DLC In Virginia Residential Homes, in years 2015 and 2020

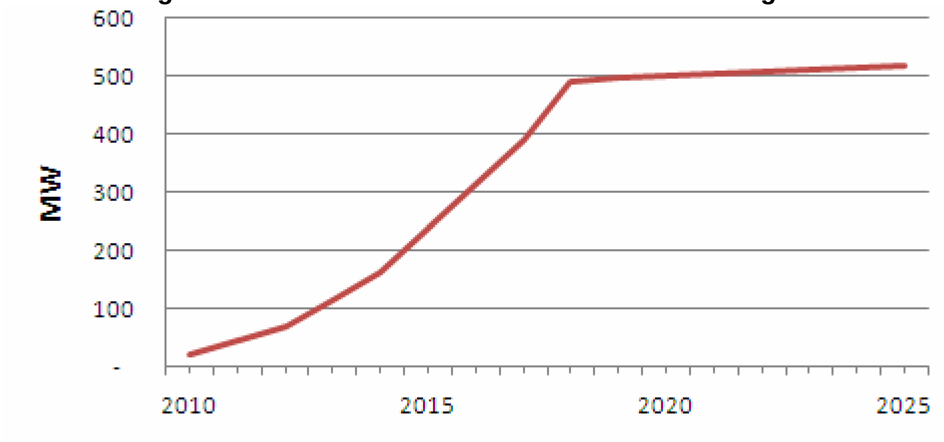
INPUTS		
Residential Peak Demand (MW)	14,300	
Residential Customers: Total [a]	3,463,276	
Residential Customers: Single Family [a]	2,164,854	
Residential Customers: Multi-Family [a]	1,271,422	
Eligible Residential Customers: Single Family [b,c]	1,515,398	
Eligible Residential Customers: Multi-Family [b,d]	800,996	
Load Reduction per AC-DLC per Single-Family Unit (kW)	1.0	
Load Reduction per AC-DLC per Multi-Family Unit (kW)	0.6	
DR Participation Rate (of eligible customers): Low	15%	
DR Participation Rate (of eligible customers): Medium	25%	
DR Participation Rate (of eligible customers): High [d]	35%	
RESULTS	**2015**	**2020**
Residential Potential DR Load Reduction: Low (MW)	143	299
Residential Potential DR Load Reduction: Med (MW)	238	499
Residential Potential DR Load Reduction: High (MW)	333	699

Notes:
a. Residential customers reflect number of housing units, as reported from Economy.com.
b. Residential accounts without central AC are assumed to have no participation.
c. Analysis assumes 70% of single-family residences have central AC.
d. Analysis assumes 63% of multi-family residences have central AC.
d. Higher participation than applied in the High Scenario is possible through design of program features, such as "opt-out" participation where participants are included in a program unless they chose to "opt-out".

Figure 5 shows the resulting residential load shed reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

[8] Programs where participants are included in a program unless they chose to "opt-out" experience much higher participation rates. One utility is proposing a "hybrid" program for new construction, where existing customers must opt-in and new construction customers must opt-out. This program assumes that 70% of new construction customers will enroll in the initial years, and 80% in later years (Summit Blue, 2008b).

Figure D-5. Potential Residential Load Shed in Virginia



D.5.4. Room Air Conditioners

Other DR residential programs could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent DR provider is exploring the possibility of having manufacturers of room AC units embedding a home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications. Callable load reductions from room air conditioners would provide a significant boost to load control capability and these reductions would be dispatchable in less than ten minutes. Some utilities are projecting to add a large number of new room air conditioners in the next five to ten years. The additional participation of a fraction of these room AC units could provide a substantial increase to the AC DLC program.

D.5.5. Other Appliances

Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units can produce additional kW reductions. This could include electric hot water heaters and pool pumps. However, the saturation of electric hot water heaters is lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Virginia utilities would most likely be calling DR events.

D.6.Commercial and Industrial DR Potential in Virginia

Appropriate commercial sector DR programs will vary according to customer size and the type of facility. Direct load control of space conditioner equipment is a primary DR strategy intended for small commercial customers (e.g., under 100 kW peak load), although TOU rates combined with promising new thermal energy storage technologies could prove an effective combination. Mid-to-large commercial customers and smaller industrial customers could best be targeted for a curtailable load program requiring several hours of advanced notification or, where practical, for an Auto-DR program that can deliver load reductions with no more than ten minutes of advance notice. Thermal energy storage and other scheduled load control programs may also be applicable for some larger buildings or water pumping customers. In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts. These pricing programs are discussed in Section 3.2. However, for the purposes of this assessment, a focus on these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

The following DR program descriptions apply to both commercial and industrial customers:

- Small business direct load control (air conditioning)—Small commercial customers (under 100 kW peak load) account for a majority of customer accounts but typically only about one-quarter of total commercial load. Due to the nature of small businesses, particularly their small staffs for which energy management is a relatively low priority, it is not practical to rely on active customer response to load control events. Thus, small businesses may best be viewed in the same way as residential customers for purposes of DR.
- Curtailable load program—This program would be applicable to commercial and industrial customers willing to commit to self-activated load reductions of a minimum of perhaps 50 kW in response to a notice and request from a utility. The minimum curtailment threshold is designed to improve program cost-effectiveness by ensuring that recruitment and technical assistance costs are used for customers who can deliver significant load reductions. Advanced notice requirements would likely be two hours— long enough to allow customers an opportunity to prepare but short enough to maintain the DR resource as a viable resource that can be dispatched by operations staff. Enabling technologies would vary greatly, but utilities would educate customers about alternatives and could work with equipment vendors to facilitate equipment acquisition and installation. Incentives would be paid as capacity payment (in $/kW-month) or a discount on the customers' demand charges. Utilities could also offer a voluntary version of the program to attract greater participation. Customers would not commit to load reductions, but incentives would be lower and would be paid only on the reductions achieved during curtailment events.
- Automated demand response (Auto-DR)—This program would be marketed to facilities such as high-rise office buildings and large retail businesses that have energy management and control systems (EMCS) that monitor and control HVAC systems, lighting, and other building functions. The benefits of Auto-DR over curtailable load programs include customer loads curtailments with as little as ten minutes notice and greater assurance that customers will reduce loads by at least their contracted amount. Incentives would be paid as either capacity payments or demand charge discounts, but would be greater than for curtailable load program participants due to the additional technology investment that may be required and the allowance of curtailments on relatively short notice. UTILITIES would offer extensive technical assistance in setting up Auto-DR capability and would potentially provide financial assistance as well for customers making long-term commitments.
- Scheduled load control programs (including thermal energy storage)—Scheduled load control can help reduce utility peak demand, especially through shifting of space cooling loads enabled by thermal energy storage technologies. Large-customer TES systems could be promoted along with customer commitments to reduce operation of chillers or rooftop air conditioners during specified peak hours. Customers' return on investment can be increased by encouraging migration to a TOU rate, which would offer a rate discount for many of the hours that TES systems are recharging cooling capacity. Water pumping systems are typically good candidates for scheduled load control programs and utilities can investigate opportunities in the municipal water supply and irrigation sectors. Other, less traditional, opportunities may also be available, such as the leisure/resort industry's limiting recharging of electric golf carts to off-peak hours.
- Emergency under-frequency relay (program add-on)—Under-frequency relays (UFRs) automatically shut off electrical circuits in response to the circuits exceeding pre-set voltage thresholds specified by the utility. Use of UFRs is a valuable addition to a DR portfolio because the load response is both automatic and virtually instantaneous. UFRs can best be integrated into another DR program where participants are already engaging in load curtailment activities. It is expected that some customers who might consider participating in a DR program will not be willing to allow loads to be controlled via UFR since they would not receive any advanced notice. Incentives would also need to be greater to attract participants and provide acceptable compensation. However, the benefits of UFRs warrant their consideration as part of a utility's proposed DR portfolio.

D.6.1. Commercial DR Potential in Virginia

To estimate potential load reductions for commercial units, a straight-forward approach of applying load shed participation rates and curtailment rates directly to commercial peak demand.

First, assumptions were made on the percentage of commercial customers who are willing to participate in DR programs. One study applied commercial participation rates ranging from 11% to 48% for commercial customers (Summit Blue 2008a). Table D-4 displays participation rates for various types of commercial customers, disaggregated into two different peak demand categories (<300kW and >300kW).

Table D-4. Examples of Commercial Load Shed Participation Rates

	Peak Category	
Customer Segment	<300kW	>300kW
Office Buildings	11% - 15%	45% - 48%
Hospitals	13%	48%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Supermarkets	12%	33%
Restaurants	11%	39%
Other Government Facilities	15%	44%
Entertainment	13%	41%
Source: Summit Blue 2008a.		

Because facility-specific data was not available for Virginia, three conservative scenarios for participation rates were applied. A medium-scenario load participation rate of 20% was applied as it appears to be an average participation rate found by utilities with DR programs in place. A low scenario of 10% and a high scenario of 30% are applied.

Then, assumptions were made for curtailment rates, based on existing estimates of the fraction of load that has been shed by commercial customers enrolled in event-based DR programs callable by the utility. Table D-5 displays curtailment rates for various types of commercial customers, which range from 13% to 43%. For the purposes of this analysis, 3 conservative scenarios were applied: a low curtailment rate of 15%, a medium curtailment rate of 20%, and a high rate of 25%.

Table D-5. Examples of Commercial Curtailment Rates

Customer Segment	Average Curtailment Rate
Office Buildings	21%
Hospitals	18%
Hotels	15%
Educational Facilities	22%
Retail	18%
Supermarkets	13%
Restaurants	17%
Other Government Facilities	38%
Entertainment	43%
Source: Summit Blue 2008a.	

Table D-6 displays the input data and results. In summary, the commercial sector results are:

- A medium scenario reduction of 235 MW is possible by 2015, and 517 MW by 2020;

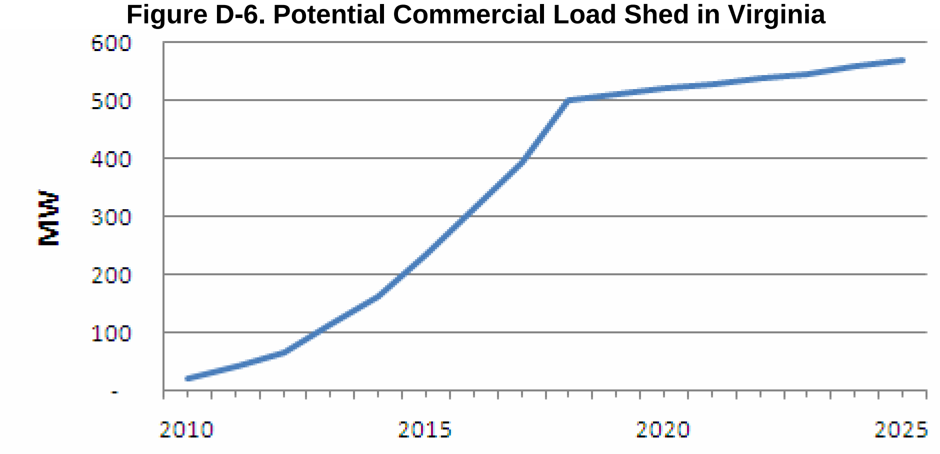
- A low scenario reduction of 88 MW is possible by 2015, and 194 MW by 2020;
- A high scenario reduction of 441 MW is possible by 2015, and 970 MW by 2020.

Table D-6. Potential Commercial Load Shed in Virginia, in Years 2015 and 2020

INPUTS		
Commercial Peak Demand (MW)	12,933	
Load Shed Participation Rate: Low	10%	
Load Shed Participation Rate: Medium	20%	
Load Shed Participation Rate: High	30%	
Curtailment Rate: Low	15%	
Curtailment Rate: Medium	20%	
Curtailment Rate: High	25%	
RESULTS	**2015**	**2020**
Commercial DR load reduction: Low (MW)	88	194
Commercial DR load reduction: Med (MW)	235	517
Commercial DR load reduction: High (MW)	441	970

Figure 6 shows the resulting commercial load shed reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-6. Potential Commercial Load Shed in Virginia



DR programs that move towards the auto-DR concept can typically provide some load sheds that only require ten-minute notification or less. While some customer surveys have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation (ConEd 2008). The value of DR and the design of DR programs should take into account system operations. Ten-minute notice DR can be valuable in helping defer some investment in T&D. While not all customers may choose to provide ten-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource. This type of DR is often a more valuable form of DR with higher savings for the utility, and utilities are often ready to pay up to twice as much to customers for this short-notice responsiveness.

Industrial DR Potential in Virginia

A similar analysis was conducted for the industrial sector: load shed participation rates and curtailment rates were applied to industrial peak demand. A previous study found industrial participation rates to vary from 25% for facilities <300kW, to 50% for >300kW (Summit Blue

2008a).For this study, the following rates were applied to participation: Low (20%); Medium (30%); and High (40%).

Previous studies have found industrial curtailment rates to vary from 17% (Quantec 2007), to 30% (Consortium 2004), to 75% (Nordham 2007), resulting in a mean of 41%. The following conservative rates were applied to curtailment for this study: Low (20%); Medium (30%); and High (40%). With these participation rates and potential load curtailments, the high load reduction potential for the overall industrial sector loads is 16% (i.e., 40% participation and 40% of that load participating).

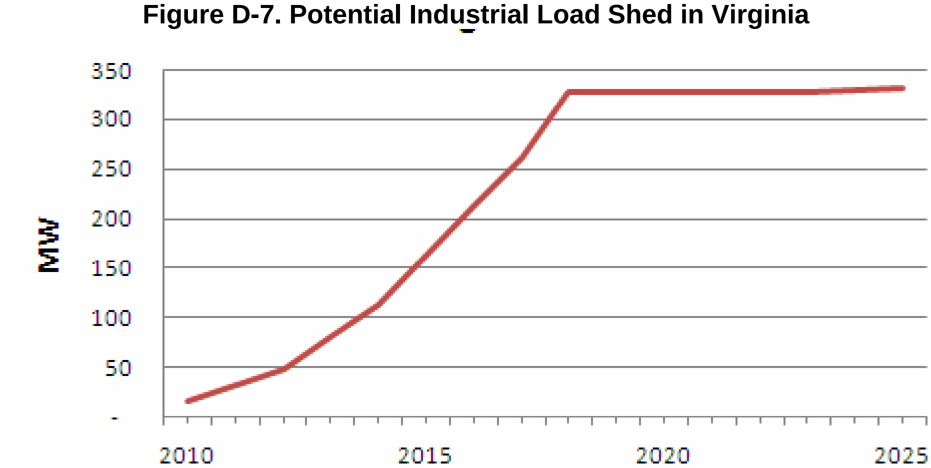
Table D-7 displays the input data and results. The medium scenario estimates 162 MW reduction of industrial peak demand possible by 2015, and 327 MW reduction of industrial peak demand possible by 2020. The low scenario estimates a 72 MW reduction by 2015 and a 145 MW reduction by 2020. The high scenario estimates a 289 MW reduction by 2015 and a 582 MW reduction by 2020.

Table D-7. Potential Industrial Load Shed in Virginia, in Years 2015 and 2020

INPUTS		
Industrial Peak Demand (MW)	3,636	
Load Participation Rate: Low	20%	
Load Participation Rate: Medium	30%	
Load Participation Rate: High	40%	
Curtailment Rate: Low	20%	
Curtailment Rate: Medium	30%	
Curtailment Rate: High	40%	
RESULTS	**2015**	**2020**
Industrial DR load reduction: Low (MW)	72	145
Industrial DR load reduction: Med (MW)	162	327
Industrial DR load reduction: High (MW)	289	582

Figure D-7 shows the resulting industrial load shed reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-7. Potential Industrial Load Shed in Virginia



The largest load reductions, and often the most cost-effective, may be found in Virginia's largest commercial and industrial customers. Data concerning these largest facilities were not available in Virginia so estimates are not quantified separately from the industrial analysis given in the previous section.

D.6.2. Commercial and Industrial Backup Generation Potential in VA

Emergency backup generation is a prominent component of a callable load program strategy. Some of the emergency generators not currently participating in DR programs may not be permitted for use as a DR resource and regulations may further limit the availability of emergency generation for DR. In some cases, backup generators may not be equipped with the start-up equipment to allow the generator to participate in short-term notification programs. Utilities could consider a program to assist customers with equipment specification and set-up to promote DR program participation by back-up generators.

In some instances, there may be environmental restrictions on emergency generation. Emissions of emergency generation may be regulated, and the future of such regulations may add some uncertainty. However, some areas have been able to have such restrictions lifted during system emergencies.

Two approaches can increase the amount of emergency generation in DR programs: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Customer-owned Emergency Generation
To increase customer-owned emergency generation, utilities may assist customers with ownership of grid-synchronized emergency generation. Utilities may offer to pay for all equipment necessary for parallel interconnection with the utility grid, as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from a utility's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption.

Utility-owned Emergency Generation
A second approach to increasing the availability of emergency generation for DR is by locating generation at customer sites that can be owned by a utility. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs. Participants would likely receive capacity payments ($/kW-month) and/or energy payments ($/kWh) in exchange for granting a utility to dispatch the units for a limited number of events and total hours per year.

Backup Generation in Virginia
A Distributed Energy Resources workshop, coordinated by the Alexandria Research Institute (ARI) and the Virginia State Corporation Commission, was held in May, 2002. The workshop identified the implications of distributed resources for the various major stakeholders and suggested a role for the Commonwealth in developing policies to promote, control or otherwise affect their development. The workshop concluded that distributed energy resources in Virginia offer a potential additional source of electrical energy supply over the next several years , with estimates ranging from 20% to 40% of installed capacity available from central power stations (CIMAP 2002).

Total Virginia back-up generation capacity for 2008 is estimated at approximately 1.79 GW.[9] Additional analysis revealed that the commercial back-up capacity is almost half of the total capacity, 896 MW.[10] Assuming a medium scenario that 40% of the total backup in Virginia is available for load

[9] Back-up generation capacity in Virginia was estimated from form EIA-861 filings submitted by utilities nationwide (EIA, 2006). However, only utilities providing approximately one-quarter of total kWh report these numbers. It was assumed that the prevalence and usage of distributed generation in the remaining 75% of utilities is similar.

[10] The analysis first determined the back-up generator population nation-wide, and then scaled the data down to the South Atlantic region (CBECS resolution), accounting for proportional differences in building stock nation-

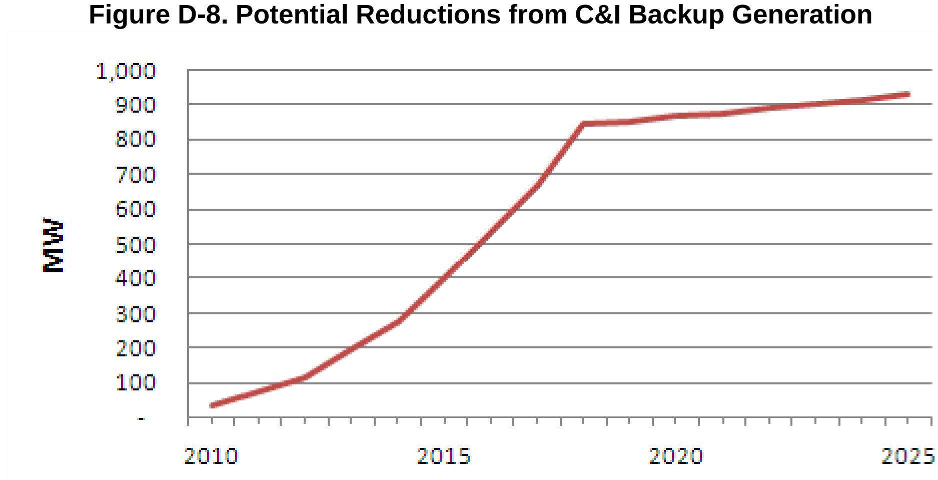
shed, then 402 MW of backup generation is available by 2015 and a 865 MW of backup generation is available by 2020 (see Table D-8). The low scenario estimates a 302 MW reduction by 2015 and a 649 MW reduction by 2020. The high scenario estimates a 503 MW reduction by 2015 and a 1,082 MW reduction by 2020.

Table D-8. Potential Reductions from C&I Backup Generation in Virginia, in Years 2015 and 2020[a]

INPUTS		
Total Backup Generation Capacity in VA (MW)	2,163	
Backup Generation Potential (%): Low	30%	
Backup Generation Potential (%): Medium	40%	
Backup Generation Potential (%): High	50%	
RESULTS	**2015**	**2020**
Potential Reduction from C&I Backup Generation (MW): Low	302	649
Potential Reduction from C&I Backup Generation (MW): Medium	402	865
Potential Reduction from C&I Backup Generation (MW): High	503	1,082

Figure D-8 shows the resulting commercial and industrial backup generation reductions possible for Virginia, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-8. Potential Reductions from C&I Backup Generation



D.6.3. Pricing and Rates

In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs callable by the utility. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts; however, for the purposes of this assessment, a focus on the these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

New rates may be introduced as part of a DR program, and may include real-time prices, or other time-differentiated rates, for commercial and industrial customers, and a modification of any existing

wide and region-wide. The region-wide results were then scaled down to Virginia specifically using the ratio of Virginia population to regional population.

residential time-of-use (TOU) rates. Any new rate structures would be designed to reduce system demand during peak periods and provide an opportunity for customers to reduce electric bills through load shifting.

Critical peak pricing (CPP) is a viable option for inclusion in a DR portfolio. In FERC's 2006 survey of utilities offering DR programs (citation below), roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The apparent lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. EPA (below), which found only four large-customer CPP programs, all of them in California. The pilot programs in California linked the CPP rate with "automated demand response" technologies that provide most of the impact. The CPP rate itself, and the price incentive that it creates, is not the driver behind the load reductions.

As stated, rate pricing options were not analyzed in this analysis. Event-based pricing programs achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs[11] show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed programs and pricing programs may come down to customer preferences and decisions by policy makers on the emphasis of DR efforts.

A time-differentiated rate is another option to consider that may not be "callable." Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).[12] The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.[13, 14]

[11] See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot—Final Report," March 16, 2005. Web reference: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

[12] See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

[13] One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

D.7.Summary of DR Potential Estimates in Virginia

Table D-9 shows the resulting load shed reductions possible for Virginia, by sector, for years 2015, 2020, and 2025. The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities. The high scenario results show a reduction in peak demand of 1,566 MW (5.4% of 2015 peak demand) is possible by 2015; 3,332 MW (10.8% of 2020 peak demand) is possible by 2020; and 3,537 MW (10.8% of 2025 peak demand) is possible by 2025. The more conservative medium scenario results show a reduction in peak demand of 1,038 MW (3.6% of 2015 peak demand) is possible by 2015; 2,209 MW (7.2% of 2020 peak demand) is possible by 2020; and 2,345 MW (7.2% of 2025 peak demand) is possible by 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

These estimated reductions in peak demand are within a range to be expected for a population of Virginia's size. Estimates of DR in other states show that the estimates calculated here for Virginia are conservative: 15% reductions in peak demand in Florida are possible by 2023 (Elliot et al. 2007a), and 13% are possible in Texas, also by year 2023 (Elliot et al. 2007b). DR potential for a utility in New York was estimated to be 9.3% of peak demand in 2017 (Summit Blue 2008a). This finding is similar to that of a recent analysis estimating that peak load reductions from DR in the Northeast will be 8.2% of system peak load in 2020 and more than 11% by 2030 (EPRI and EEI 2008). Estimation methods differ among the studies, but nonetheless show that the 8% reductions in Virginia are realistic for the medium scenario, and the high scenario estimates for approximately 12% are achievable as well. A previous study on DR in Virginia contains similar results, revealing that 8.8% reductions in peak demand are possible by 2017 through DR programs (Summit Blue 2007c). The small difference in the estimated potential is attributable to different estimation methods and slightly varying inputs including participation rates, residential load reductions, and target years for full participation rates. In addition, the 2007 study included quantified estimates for reductions through pricing programs, in addition to direct load control reductions.

[14] The complementary of event-based load shed programs with RTP tariffs is assessed in: Violette, D., R. Freeman, and C. Neil. *DR Valuation and Market Analysis—Volume II: Assessing the DR Benefits and Costs*, Prepared for the International Energy Agency, TASK XIII, Demand-Side Programme, Demand Response Resources, January 6, 2006. Updated results are presented in: Violette, D. and R. Freeman; "Integrating Demand Side Resource Evaluations in Resource Planning;" *Proceedings of the International Energy Program Evaluation Conference (IEPEC)*, Chicago, August 2007 (also at www.IEPEC.com).

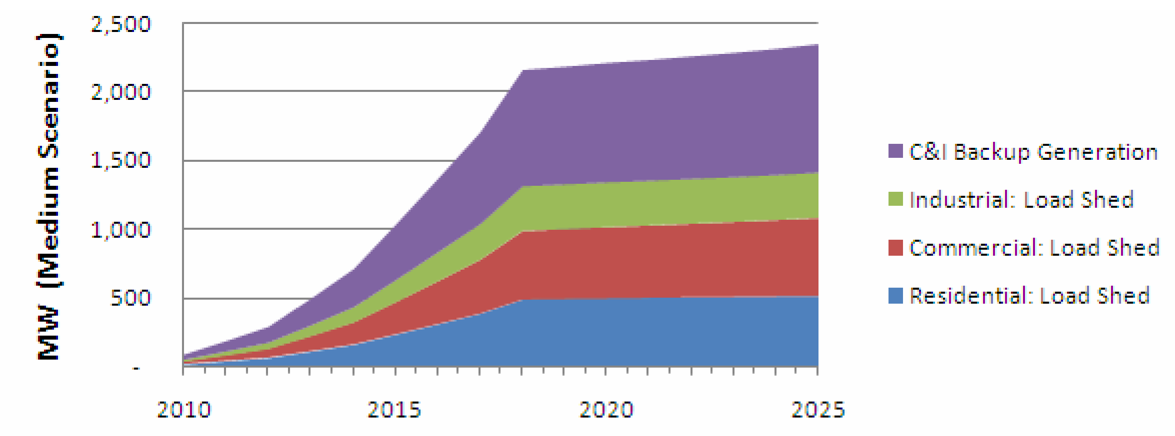
Table D-9. Summary of Potential DR in Virginia, By Sector, for Years 2015, 2020, and 2025[a]

	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Residential: Load Shed (MW)	143	299	310	238	499	516	333	699	723
Commercial: Load Shed (MW)	88	194	213	235	517	567	441	970	1,063
Industrial: Load Shed (MW)	72	145	147	162	327	331	289	582	588
C&I Backup Generation (MW)	302	639	698	402	865	930	503	1,082	1,163
Total DR Potential (MW)	605	1,288	1,367	1,038	2,209	2,345	1,566	3,332	3,537
DR Potential as % of Total Peak Demand (30,065 MW)	2.1%	4.2%	4.2%	3.6%	7.2%	7.2%	5.4%	10.8%	10.8%

a. See Section 3 for underlying data and assumptions.

Figure D-9 shows the resulting load shed reductions possible for Virginia, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure D-9. Potential DR Load Reductions in Virginia by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates include assumptions based on utility experience regarding growth rates, participation rates, and program design, among others, and will adjust accordingly if differing assumptions are made. The assumptions made are believed to be conservative, and reflect minimum achievable DR potential. For example, participation rates for all of the sectors are based on experience in other states, and are based primarily on customer awareness, the ability to have automated response, and the adequacy of reward. If the statewide education program now required in Virginia promotes DR programs and adequate incentives are offered, then participation rates higher than the medium scenario are entirely realistic.

D.8.Recommendations

This assessment indicates that the system peak demand can be reduced by approximately 7.8% or 2,209 MW in 2020 in the medium case. In the high case, the reduction can be as high as 11.7% or 3332 MW. The high case is considered to be within a reasonable range if aggressive action begins by the end of 2009, providing for a twelve-year rollout of the DR efforts (at the beginning of 2010 through the end of 2020). Key recommendations include:

- Appropriate financial incentives for the Virginia' utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. The basic premise is that a utility's least-cost plan should also be its most profitable plan. Developing these incentives poses some complexities in that MW's in that DR programs likely will be bid into PJM's DR programs and will receive financial payments from PJM. Whether this provides adequate incentives for the appropriate development of DR programs in Virginia should be examined.

- It is important that the DR programs be integrated with the delivery of EE programs. Many gains in delivery efficiency are possible by combining and cross-marketing EE and DR programs. These can include new building codes and standards that include not only energy efficiency construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response. This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- Plan for at-scale programs through the rollout period. Pilot programs can be important in determining the appropriate design of cost-effective DR programs. However, there are established DR programs and technologies. Even with the unique circumstances in Virginia, these programs can be designed for deployment at scale. However, this approach recognizes that the first year of program deployment and possibly the second year should be designed to test key design components as part of a program shakeout. The third year of a program that should represent an efficient design and an at-scale program. DSM programs are designed to be flexible and undergo year-to-year changes due to market, customer and technology factors. This will always be the case and the benefits of discrete pilot program can limit overall program participation for a number of years resulting in "lost DR MWs." The politics of DSM and diverse positions of parties can result in a compromise in the implementation of programs leading to a two to three-year pilot program. This can delay the delivery of DR at scale resulting in higher overall costs. The over-use of pilots that do not acknowledge the ability of a program roll-out to have at-scale deliver as its goal in year three, but to also have tests of design components and decision nodes built into the first two year of program rollout can result in "death by piloting" for attainable DR MWs. Also, a decision to run a pilot program must be based on the assumption that the program will not have enough flexibility in design and on-going decision nodes during the first two years to allow for the ramp up into full scale efficient deployment in year three.

- Load reduction programs typically have less need for pilot programs as the reductions are defined by the equipment and processes outlined by the program for each participant. Time differentiated pricing is a cornerstone of efficient electric markets and the design of these programs may need more pilot testing as the customer response to pricing is voluntary and not set (as often) by program design.

- Virginia has a history of time-differentiated rates. Pricing should form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

- Key programs that be considered for roll-out and can be designed within a 12-month period include:
    - Residential and small business AC direct load control using switches or thermostats (or giving customers their choice of technology).[15]
    - Auto-DR programs providing direct load curtailment for larger commercial and industrial customers.
    - Callable interruptible programs with manual response to an event notification for larger commercial and industrial customers where auto-DR approaches are not acceptable to the customer or technically not feasible.
    - Aggressive enrollment of back-up generators in DR programs.

- Customer education should be included in DR efforts (as also recommended by the SCC Sub-group 3 (SCC 2007). There is some perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight

- Increase clarity and coordination between the Federal and State agencies and programs (as also recommended by the SCC Sub-group 3 (SCC 2007). 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.

[15] This approach is currently being used successfully by LGE Energy.

Appendix E - Combined Heat and Power

E.1.Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

E.1.1. Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have “excess” thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

E.1.2. Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:

Low load factor applications. These represent markets that otherwise could not support CHP due to a lack of thermal load.

Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.

- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- *Identify existing CHP in the state.* The analysis of CHP potential starts with the identification of existing CHP. In Virginia, there are 9 operating CHP plants totaling 322 MW of capacity. This existing CHP capacity is deducted from any identified technical potential.

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the iMarket, Inc*. MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHI were utilized to identify potential CHP sites by SIC code or application, and location (county). The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kiloWatt-hours.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. Tables E-1 through E-3 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have

25-30% more capacity than traditional. Therefore, the totals for the entire state, all four market segments, discounts these applications to avoid double counting.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2025 by target market sectors in Virginia. The growth factors used in the analysis for growth between the present and 2025 by individual sector are shown in Table E-4. These growth projections provided by ACEEE were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table E-5.

Table E-1. Virginia Technical Market Potential for CHP in Existing Facilities—Industrial Sector

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Industrial (Traditional, High Load Factor													
20	Food	140	21.0	30	22.5	27	67.5	7	89.8	1	44.5	205	245.3
21	Tobacco Manufacturers							1	5.6	0			5.6
22	Textiles	50	5.6	22	12.4	13	24.4	1	15.4	4	334.1	90	391.9
24	Lumber and Wood	207	6.2	53	8.0	14	7.0	2	22.3	1	59.1	277	102.5
25	Furniture	19	0.9	12	2.7	0	0.0	4	50.2	0		35	53.8
26	Paper	44	6.6	23	17.3	44	110.0	1	15.7	19	1,441.0	131	1,590.5
27	Printing/Publishing	76	11.4	7	5.3	0	0.0	1	5.5	0		84	22.1
28	Chemicals	63	9.5	20	15.0	28	70.0	2	23.3	6	441.6	119	559.4
29	Petroleum Refining	26	3.9	2	1.5	0	0.0	0	0.0	1	54.2	29	59.6
30	Rubber/Misc Plastics	58	2.6	34	7.7	37	27.8	2	19.0	1	67.8	132	124.7
32	Stone/Clay/Glass	4	0.6	8	6.0	0	0.0	1	11.0	0	0.0	13	17.6
33	Primary Metals	11	0.4	4	0.8	4	2.5	0	0.0	0	0.0	19	3.7
34	Fabricated Metals	28	1.3	4	0.9	3	2.3	0	0.0	1	82.4	36	86.8
35	Machinery/Computer Equip	10	0.4	4	0.8	0	0.0	1	11.0	0	0.0	15	12.1
37	Trasportation Equip.	46	3.5	20	7.5	25	31.3	2	23.0	1	82.4	94	147.6
38	Instruments	14	1.1	2	0.8	2	2.5	1	5.0	0	0.0	19	9.3
39	Misc Manufacturing	7	0.3	3	0.6	0	0.0	0	0.0	0	0.0	10	0.8
	Total	803	75.1	248	109.4	197	345.1	26	296.7	35	2607.1	1308	3433.3

Table E-2. Virginia Technical Market Potential for CHP in Existing Facilities—Commercial, Traditional CHP

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial, Multifamily(Traditional, High Load Factor)													
6513	Apartments	249	18.7	90	33.8	14	17.5		0.0		0.0	353	69.9
4222, 5142	Warehouses	16	2.4	13	9.8	1	2.5		0.0		0.0	30	14.7
4941, 4952	Water Treatment/Sanitary	21	3.2	22	16.5	20	50.0	2	25.0		0.0	65	94.7
7011, 7041	Hotels	839	94.4	146	82.1	58	108.8	2	18.8		0.0	1045	304.0
8051, 8052, 8059	Nursing Homes	222	33.3	116	87.0	13	32.5		0.0		0.0	351	152.8
8062, 8063, 8069	Hospitals	65	9.8	34	25.5	77	192.5	1	12.5		0.0	177	240.3
8221, 8222	Colleges/Universities	95	14.3	75	56.3	35	87.5	7	87.5	1	25.0	213	270.5
9223, 9211 (Courts), 9224 (firehouses)	Prisons	17	2.6	54	40.5	45	112.5	1	12.5		0.0	117	168.1
	Total C/I High LF	1524	178.5	550	351.4	263	603.8	13	156.3	1	25	2351	1314.8
Commercial (Traditional, Low Load Factor)													
7542	Carwashes	54	8.1		0.0		0.0		0.0		0.0	54	8.10
8412	Museums	68	10.2	6	4.5		0.0		0.0		0.0	74	14.70
7211, 7213, 7218	Laundries	44	6.6	3	2.3		0.0		0.0		0.0	47	8.85
7991, 00, 01	Health Clubs	133	20.0	14	10.5		0.0		0.0		0.0	147	30.45
7992, 7997-9904, 7997-9906	Golf/Country Clubs	174	26.1	14	10.5		0.0		0.0		0.0	188	36.60
8211, 8243, 8249, 8299	Schools	813	30.5	155	29.1	11	6.9		0.0		0.0	979	66.43
	Total C/I Low LF	1286	101.4	192	56.813	11	6.875	0	0	0	0	1489	165.13
	Total C/I Traditional	2810	279.9	742	408.19	274	610.625	13	156.3	1	25	3840	1480.0

Table E-3. Virginia Technical Market Potential for CHP in Existing Facilities—Commercial, Cooling

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial Cooling, High Load Factor													
7011, 7041	Hotels- Cooling	839	125.9	146	109.5	58	145.0	2	25.0			1045	405.4
8051, 8052, 8059	Nursing Homes- Cooling	222	40.0	116	104.4	13	39.0		0.0			351	183.4
8062, 8063, 8069	Hospitals- Cooling	66	11.9	34	30.6	78	234.0	1	15.0			179	291.5
	Total Cooling High LF	1127	177.7	296	244.5	149	418	3	40			1575	880.2
Commercial Cooling, Low Load Factor													
43	Post Offices	60	9.0		0.0		0.0					60	9.0
4581	Airports	12	1.8		0.0		0.0					12	1.8
6512	Office Buildings - Cooling	1408	105.6	563	211.1	141	176.3					2112	493.0
7832	Movie Theaters	53	8.0		0.0		0.0					53	8.0
52,53,56,57	Big Box Retail	799	119.9	177	132.8	56	140.0					1032	392.6
5411, 5421, 5451, 5461, 5499	Food Sales	1097	82.3	132	49.5	13	16.3					1242	148.0
5812, 00, 01, 03, 05, 07, 08	Restaurants	1130	84.8	9	3.4		0.0					1139	88.1
	Total Cooling Low LF	4559	411.2	881	396.75	210	332.5	0	0	0	0	5650	1140.48
	Total Cooling	5686	588.9	1177	641.25	359	750.5	3	40	0	0	7225	2020.7
	Total C/I All Types	8496	868.8	1919	1049.4	633	1361.13	16	196.3	1	25	11065	3500.6

Table E-4. Virginia Sector Growth Projections Through 2025

SIC Code	Market Sector	2008-2025 Real Growth
20	Food	10.4%
22	Textiles	0.0%
24	Lumber and Wood	10.2%
25	Furniture	10.2%
26	Paper	10.2%
27	Printing/Publishing	0.0%
28	Chemicals	69.5%
29	Petroleum Refining	69.5%
30	Rubber/Misc Plastics	69.5%
32	Stone/Clay/Glass	31.9%
33	Primary Metals	30.3%
34	Fabricated Metals	30.3%
35	Machinery/Computer Equip	63.9%
37	Trasportation Equip.	31.7%
38	Instruments	48.8%
39	Misc Manufacturing	10.2%
4222, 5142	Warehouses	0.0%
4941, 4952	Water Treatment/Sanitary	50.6%
5411, 5421, 5451, 5461, 5499	Food Sales	91.9%
5812, 00, 01, 03, 05, 07, 08	Restaurants	60.5%
7011, 7041	Hotels	60.5%
7211, 7213, 7218	Laundries	11.3%
7542	Carwashes	11.3%
7991, 00, 01	Health Clubs	60.5%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	60.5%
8051, 8052, 8059	Nursing Homes	32.8%
8062, 8063, 8069	Hospitals	32.8%
8211, 8243, 8249, 8299	Schools	32.8%
8221, 8222	Colleges/Universities	32.8%
8412	Museums	60.5%
9223, 9211 (Courts), 9224 (firehouses)	Prisons	13.2%
6513	Apartments	0.0%
43	Post Offices	44.7%
4581	Airports	44.7%
52,53,56,57	Big Box Retail	91.9%
7832	Movie Theaters	60.5%
7011, 7041	Hotels- Cooling	60.5%
8051, 8052, 8059	Nursing Homes- Cooling	32.8%
8062, 8063, 8069	Hospitals- Cooling	32.8%
6512	Office Buildings - Cooling	0.0%

Table E-5. CHP Market Segments, Virginia Existing Facilities and Expected Growth 2007-2020

Market	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Traditional High Load Factor Market						
Existing Facilities	254	461	949	453	2,632	4,748
New Facilities	82	126	267	140	501	1,116
Total	335	587	1,216	593	3,133	5,864
Traditional Low Load Factor Market						
Existing Facilities	101	57	7	0	0	165
New Facilities	39	21	2	0	0	62
Total	141	78	9	0	0	227
Cooling CHP High Load Factor Market (partially additive)						
Existing Facilities	178	245	418	40	0	880
New Facilities	80	96	153	13	0	341
Total	258	340	571	53	0	1,221
Cooling CHP Low Load Factor Market						
Existing Facilities	411	397	333	0	0	1,140
New Facilities	209	144	123	0	0	476
Total	621	541	455	0	0	1,616
Total Market including Incremental Cooling Load						
Existing Facilities	819	988	1,414	465	2,632	6,318
New Facilities	354	320	437	144	501	1,756
Total	1,173	1,308	1,851	608	3,133	8,074

Note: High load factor cooling market is comprised of a portion of the traditional high load factor market that has both heating and cooling loads. The total high load factor cooling market is shown, but only 30% of it is incremental to the portion already counted in the traditional high load factor market. Growth rates were extrapolated for the 2020-2025 market penetration forecast.

E.2.Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP. For this screening analysis, a fairly simple methodology was used:

E.2.1. Electric Price Estimation

- Retail electric price forecasts based on were used as the starting point for the analysis. ACEEE provided state by state estimates. The annual price forecasts provided were converted to 5 year averages for use in the market penetration model. These prices are shown in **Table E-6**.
- The electricity price assumptions for the high load factor CHP applications were as follows
  - 50-500 kW—Commercial average price
  - 500 kW to 5 MW—Industrial average price
  - 5 MW and above—90% of industrial average price
- Price adjustments for customer load factor were defined as follows:

  - High load factor—100% of the estimated value
  - Low load factor—120% of the estimated value
  - Peak cooling load—150% of the estimated value
- For a customer generating a portion of his own power with CHP, standby charges are estimated at 15% of the defined average electric rate. Therefore, when considering CHP, only 85% of a customer's rate can be avoided.

E.2.2. Natural Gas Price Estimation

- The natural gas price assumptions are based on the industrial retail price shown in the table.
  - All customer boiler fuel is assumed at the industrial rate except for the CHP market below 500 kW where the boiler gas price is assumed to be $0.50/MMBtu higher
  - All CHP fuel is assumed to be at a $0.60/MMBt discount to the retail industrial price.

Table E-6. Input Price Forecast (EIA-AEO 2007) and Virginia Industrial Electric Price Estimation[1]

Virginia Energy Prices	Avg. 2007-2009	Avg.2010-2014	Avg.2015-2019	Avg.2020-2024
Virginia Retail Electricity Prices (2006$/kWh)				
Residential	$ 0.104	$ 0.135	$ 0.151	$ 0.158
Commercial	$ 0.080	$ 0.101	$ 0.115	$ 0.121
Industrial	$ 0.065	$ 0.071	$ 0.077	$ 0.082
All Sector Avg.	$ 0.087	$ 0.108	$ 0.121	$ 0.127
Virginia Retail Natural Gas Prices (2006$/MMbtu)				
Residential	$15.456	$14.107	$14.390	$14.930
Commercial	$11.785	$10.400	$10.516	$10.870
Industrial	$9.303	$7.782	$7.923	$8.312

[1] These price vary somewhat from the reference forecast because the CHP analysis was undertaken before the final price forecasts were finalized.

E.3.CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100–20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

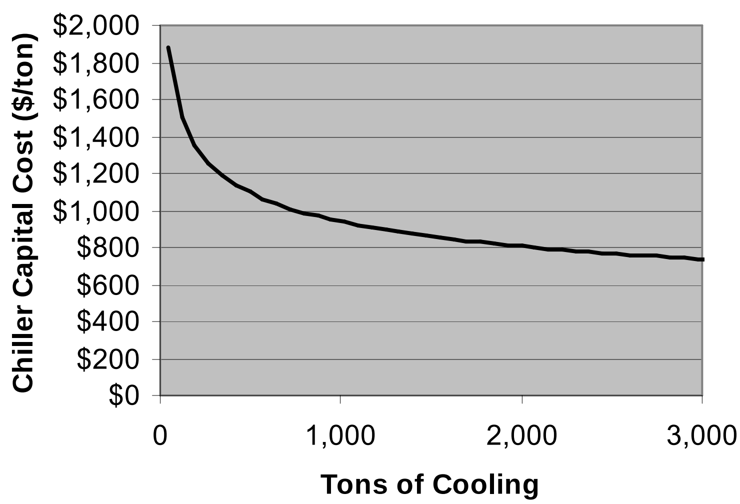
Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[16] The foundation for these updates is based on work previously conducted for NYSERDA[17], on peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory[18] and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory.[19] Additional emissions characteristics and cost and

[16] EPA CHP Partnership Program, Technology Characterizations, December 2007 (under review).
[17] *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.
[18] "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL, November 2003, http://www.osti.gov/bridge
[19] "Clean Distributed Generation Performance and Cost Analysis", DE Solutions for ORNL. April 2004.

performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI.[20] Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2007-2010 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010-2015 and 2015-2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). For this analysis, aftertreatment was only included for the 800 kW and 3000 kW engines. The installed costs in Tables E7 through E10 are based on typical national averages.

In the cooling markets, an additional cost was added to reflect the costs of adding chiller capacity to the CHP system. These costs depend on the sizing of the absorption chiller which in turn depends on the amount of usable waste heat that the CHP system produces. Figure E-1 shows this cost approximation.

Figure E-1. Absorption Chiller Capital Costs



[20] "Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators", EPRI, January 2005.

Table E-7. Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
100 kW	Installed Costs, $/kW	$2,210	$1,925	$1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4%	31.5%	32.5%
	Thermal Output, Btu/kWh	6100	5093	4874
	O&M Costs, $/kWh	0.022	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.10	0.15	0.15
	CO Emissions w/AT, lb/MWh	0.32	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.10	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO_2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	After-treatment Cost, $/kW	incl.	incl.	incl.
800 kW	Installed Costs, $/kW	$1,640	$1,443	$1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0%	35.0%	37.0%
	Thermal Output, Btu/kWh	2313	3791	3250
	O&M Costs, $/kWh	0.013	0.01	0.009
	NOx Emissions, lbs/MWh (w/ AT)	0.5	1.24	0.93
	CO Emissions w/AT, lb/MWh	1.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.47	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0068	0.0057	0.0054
	After-treatment Cost, $/kW	300	190	140
3000 kW	Installed Costs, $/kW	$1,130	$1,100	$1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9%	39.0%	41.0%
	Thermal Output, Btu/kWh	3510	3189	2982
	O&M Costs, $/kWh	0.011	0.0083	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.52	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	After-treatment Cost, $/kW	200	130	100
5000 kW	Installed Costs, $/kW	$1,130	$1,099	$1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0%	41.0%	43.0%
	Thermal Output, Btu/kWh	3046	2797	2605
	O&M Costs, $/kWh	0.009	0.008	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.55	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	After-treatment Cost, $/kW	150	115	80

Table E-8. Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
60 kW	Installed Costs, $/kW	$2,739	$2,037	$1,743
	Heat Rate, Btu/kWh	13,891	12,500	11,375
	Electric Efficiency, %	24.6%	27.3%	30.0%
	Thermal Output, Btu/kWh	6308	3791	3102
	O&M Costs, $/kWh	0.022	0.016	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.15	0.14	0.13
	CO Emissions w/AT, lb/MWh	0.24	0.22	0.20
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO_2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	After-treatment Cost, $/kW			
250 KW	Installed Costs, $/kW	$2,684	$2,147	$1,610
	Heat Rate, Btu/kWh	13,080	11,750	10,825
	Electric Efficiency, %	2.6%	29.0%	31.5%
	Thermal Output, Btu/kWh	4800	3412	2625
	O&M Costs, $/kWh	0.015	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.43	0.24	0.13
	CO Emissions w/AT, lb/MWh	0.26	0.26	0.24
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	After-treatment Cost, $/kW	500	200	90

Table E-9. Fuel Cell Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
200 kW PAFC in 2005 150 kW PEMFC in outyears	Installed Costs, $/kW	$6,310	$4,782	$3,587
	Heat Rate, Btu/kWh	9,480	9,480	8,980
	Electric Efficiency, %	36.0%	36.0%	38.0%
	Thermal Output, Btu/kWh	4250	3482	3281
	O&M Costs, $/kWh	0.038	0.017	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.07	0.07
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0056	0.0053
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, $/kW	$5,580	$4,699	$3,671
	Heat Rate, Btu/kWh	8,022	7,125	6,920
	Electric Efficiency, %	42.5%	47.9%	49.3%
	Thermal Output, Btu/kWh	1600	1723	1602
	O&M Costs, $/kWh	0.035	0.02	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.1	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0042	0.0041
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
1200 kW MCFC	Installed Costs, $/kW	$5,250	$4,523	$3,554
	Heat Rate, Btu/kWh	8,022	7,110	6,820
	Electric Efficiency, %	42.5%	48.0%	50.0%
	Thermal Output, Btu/kWh	1583	1706	1503
	O&M Costs, $/kWh	0.032	0.019	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.05	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.03
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0044	0.0042	0.0040
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Table E-10. Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
3000 KW GT	Installed Costs, $/kW	$1,690	$1,560	$1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NOx Emissions, lbs/MWh (w/ AT)	0.68	0.38	0.2
	CO Emissions w/AT, lb/MWh	0.55	0.53	0.47
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0069
	After-treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	$1,298	$1,342	$1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.007	0.006	0.005
	NOx Emissions, lbs/MWh (w/ AT)	0.67	0.37	0.2
	CO Emissions w/AT, lb/MWh	0.50	0.46	0.42
	VOC Emissions w/AT, lb/MWh	0.02	0.02	0.02
	PMT 10 Emissions, lb/MWh	0.20	0.18	0.17
	SO_2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	After-treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	$972	$944	$916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, lbs/MWh (w/ AT)	0.55	0.2	0.1
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.16	0.15	0.15
	SO_2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	After-treatment Cost, $/kW	90	75	40

E.4.Market Penetration Analysis

EEA has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-yrar increments. For this analysis, the forecast periods are 2012, 2017, and 2022. These results are interpolated to the output years 2010, 2015, 2020, and 2025. The target market is comprised of the facilities that make up the technical market potential as defined in previously in this section. Thee economic competition module in the market penetration model compares CHP technologies to purchased fuel and power in 5 different sizes and 4 different CHP application types. The calculated payback determines the potential pool of customers that would consider accepting the CHP investment as economic. Additional, non economic screening factors are applied that limit the pool of customers that can accept CHP in any given market/size. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period. The cumulative market penetration, economic potential and technical potential are defined as follows:

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic potential*, as shown in the table, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.
- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

In addition to segmenting the market by size, as shown in the table, the analysis is conducted in four separate CHP market applications (high load and low load factor traditional CHP and high and low load factor CHP with cooling.) These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (**Table E-11)**. Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[21] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

[21] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

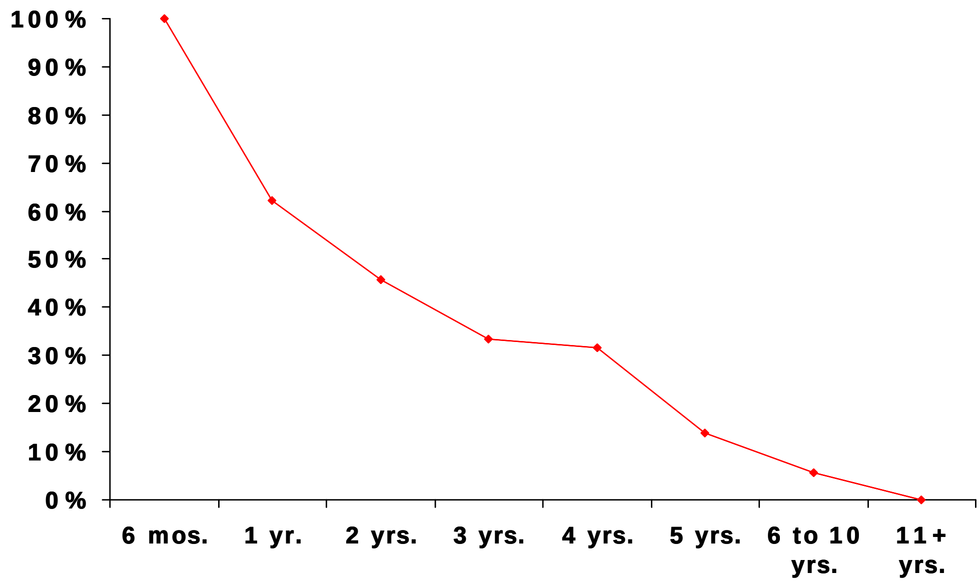
Table E-11. Technology Competition Assumed within Each Size Category

Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 - 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 - 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Figure E-2 shows the percentage of survey respondents that would accept CHP investments at different payback levels[22]. As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

[22] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July, 2005.

Figure E-2. Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion.) The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW.) These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model market cumulative market penetration estimate.

Once the market penetration is determined, the competing technology shares within a size/utility bin are based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback. (This technology allocation feature is part of the EEA CHP model that is not specifically used for this analysis.)

Three cases were run to show the effects of providing an economic stimulus for CHP market penetration consisting of a capital cost reduction of $500/kW and $1,000/kW for all CHP systems 5 MW and below. The results of the base case, without incentives, are shown in Table E-12. Table E-13 shows the results of the $500/kW incentive case. Table E-14 shows the results of the $1,000/kW incentive case.

Table E-12. Market Penetration Results for Base Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	48	249	411	468
Commercial/Institutional	3	47	109	146
Total	51	296	520	614
Avoided Cooling	0	2	6	6
Scenario Grand Total	51	299	526	620
Annual Electric Energy (Million kWh)				
Industrial	389	1,975	3,237	3,641
Commercial/Institutional	20	314	707	963
Total	409	2289	3944	4604
Avoided Cooling	0	6	16	23
Scenario Grand Total	409	2,295	3,961	4,627
Incremental Onsite Fuel (billion Btu/year)				
Industrial	2,038	10,216	16,734	18,968
Commercial/Institutional	103	1,831	4,159	5,542
Total	2,141	12,047	20,893	24,510
Cumulative Net Investment (million 2006$)	$51	$317	$573	$689
Cumulative Incentive Payments (Million 2006$)	$0	$1	$4	$7

Note: Incentive Payments in the Base Case represent fuel cell tax credits

Table E-13. Market Penetration Results for $500/kW Incentive Case

CHP Measurement	Today	2010	2015	2020	2025
Cumulative Market Penetration (MW)					
Industrial	0	51	276	467	540
Commercial/Institutional	0	8	107	236	313
Total	0	59	382	703	853
Avoided Cooling	0	1	9	17	19
Scenario Grand Total	0	60	391	721	872
Annual Electric Energy (Million kWh)					
Industrial	0	402	2,127	3,549	4,028
Commercial/Institutional	0	48	650	1,437	1,925
Total	0	450	2776	4986	5954
Avoided Cooling	0	2	22	49	67
Scenario Grand Total	0	453	2,799	5,035	6,020
Incremental Onsite Fuel (billion Btu/year)					
Industrial	0	2,118	11,103	18,613	21,395
Commercial/Institutional	0	274	3,866	8,564	11,304
Total	0	2,392	14,969	27,177	32,699
Cumulative Net Investment (million 2006$)	0	$58	$352	$630	$753
Cumulative Incentive Payments (Million 2006$)	0	$8	$96	$218	$294

Table E-14. Market Penetration Results for $1000/kW Incentive Case

CHP Measurement	Today	2010	2015	2020	2025
Cumulative Market Penetration (MW)					
Industrial	0	57	309	522	601
Commercial/Institutional	0	25	227	470	603
Total	0	82	536	992	1204
Avoided Cooling	0	1	10	19	21
Scenario Grand Total	0	83	546	1,011	1,225
Annual Electric Energy (Million kWh)					
Industrial	0	437	2,369	3,987	4,532
Commercial/Institutional	0	171	1,472	2,995	3,848
Total	0	608	3841	6982	8379
Avoided Cooling	0	3	27	57	77
Scenario Grand Total	0	611	3,867	7,039	8,456
Incremental Onsite Fuel (billion Btu/year)					
Industrial	0	2,376	12,557	21,060	24,142
Commercial/Institutional	0	952	8,490	17,392	22,200
Total	0	3,328	21,046	38,452	46,342
Cumulative Net Investment (million 2006$)	0	$66	$350	$599	$703
Cumulative Incentive Payments (Million 2006$)	0	$32	$289	$597	$764

Appendix F - The Deeper Model and Macro Model

The Dynamic Energy Efficiency Policy Evaluation Routine—or the DEEPER Model—is a 15-sector quasi-dynamic input-output impact model of the U.S. economy.[23] Although an updated model with a new name, the model has a 16-year history of use and development. See, for example, Laitner, Bernow, and DeCicco (1998) and Laitner and McKinney (2008a) for a review of past modeling efforts. The model is generally used to evaluate the macroeconomic impacts of a variety of energy efficiency (including renewable energy) and climate policies at both the state and national level. The national model now evaluates policies for the period 2008 through 2050. For the Virginia specific analysis, however, DEEPER Model covers the period between 2008 through 2025. As it is now designed, the model accepts policy inputs in the form of investments and expenditures as described throughout the report. It then evaluates the changed pattern of expenditures for the net direct and indirect impacts on the different sectors of the regional economy. DEEPER is an Excel-based analytical tool that consists generally of six sets of key modules or groups of worksheets. These six sets of modules now include:

Global data: The information in this module consists of the economic time series data and key model coefficients and parameters necessary to generate the final model results. The time series data includes the projected reference case energy quantities such as trillion Btus and kilowatt-hours, as well as the key energy prices associated with their use. It also includes the projected gross domestic product, wages and salary earnings, and levels of employment as well as information on key technology cost and performance characteristics. The sources of economic information include data from the Energy Information Administration, the Bureau of Economic Analysis, the Bureau of Labor Statistics, and Economy.com. The cost and performance characterization of key technologies is derived from available studies completed by ACEEE and others, as well as data from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). One of the more critical assumptions in this study is that alternative patterns of electricity consumption will change and/or defer the mix of investments in conventional power plants. Although we can independently generate these impacts within DEEPER, we can also substitute assumptions from the ICF Integrated Planning Model (IPM) and similar models as they may have different characterizations of avoided costs or alternative patterns of power plant investment and spending.

Macroeconomic model: This set of modules contains the "production recipe" for the region's economy for a given "base year"—in this case, 2006, which is the latest year for which a complete set of economic accounts are available for the regional economy. The I-O data, currently purchased from the Minnesota IMPLAN Group (IMPLAN 2008), is essentially a set of input-output accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other. In this case, the model is now designed to evaluate impacts for 15 different sectors, including: Agriculture, Oil and Gas Extraction, Coal Mining, Other Mining, Construction, Manufacturing, Electric Utilities, Natural Gas Distribution, Transportation and Other Public Utilities (including water and sewage), Wholesale & Retail Trade, Services, Finance, Government, and Households.

Investment, Expenditures and Energy Savings: Based on the scenarios mapped into the model, this worksheet translates the energy policies into a dynamic array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. It estimates the needed investment path for an alternative mix of energy efficiency and other technologies (including efficiency gains on both the end-use and the supply side). It also provides an estimate of the avoided

[23] There is nothing particularly special about this number of sectors. The goal is to provide sufficient detail to show key negative and positive impacts while maintaining a manageable sized model. If we choose to reflect a different mix of sectors and stay within the 15 x 15 matrix, that can be done easily. If we wish to expand the number of sectors, that would take some minor programming changes or adjustments to reflect the larger matrix.

investments needed by the electric generation sector. These quantities and expenditures feed directly into the final demand module of the model which then provides the accounting that is needed to generate the set of annual changes in final demand (see the related module description below).

Price dynamics: There are two critical drivers that impact energy prices within DEEPER. The first is a set of carbon charges that are added to retail prices of energy depending on the level of desired level of emission reductions and also depending on the available set of alternatives to achieve those reductions. The second is the price of energy as it might be affected by changed consumption patterns. In this case DEEPER employs an independent algorithm to generate energy price impacts as they reflect changed demand. Hence, the reduced demand for natural gas in the end-use sectors, for example, might offset increased demand by utility generators. If the net change is a decrease in total natural gas consumption, the wellhead prices might be lowered. Depending on the magnitude of the carbon charge, the change in retail prices might either be higher or lower than the set of reference case prices. This, in turn, will impact the demand for energy as it is reflected in the appropriate modules. In effect, then, DEEPER scenarios rely on both a change in prices and quantities to reflect changes in overall investments and expenditures.

Final demand: Once the changes in spending and investments have been established and adjusted to reflect changes in prices within the other modules of DEEPER, the net spending changes in each year of the model are converted into sector-specific changes in final demand. This, in turn, drives the input-output model according to the following predictive model:

$$X = (I-A)^{-1} * Y$$

where:

X = total industry output by sector
I = an identity matrix consisting of a series of 0's and 1's in a row and column format for each sector (with the 1's organized along the diagonal of the matrix)
A = the production or accounting matrix also consisting of a set of production coefficients for each row and column within the matrix
Y = final demand, which is a column of net changes in final demand by sector

This set of relationships can also be interpreted as

$$\Delta X = (I-A)^{-1} * \Delta Y$$

which reads, a change in total sector output equals the inverted (I-A) matrix times a change in the final spending demand for each sector. Employment quantities are adjusted annually according to exogenous assumptions about labor productivity in each of the sectors (based on Bureau of Labor Statistics forecasts).

Results: For each year of the analytical time horizon (again out to 2025 for the Virginia specific analysis), the model copies each set of results into this module in a way that can also be exported to a separate report.

Further results from Virginia's DEEPER analysis is provided to show macroeconomic trends between 5-year time periods. Although similar 2015 & 2025 results were presented in the body of this report, differences between 5-year time periods offer more reference points for the reader to understand Virginia's macroeconomic trends under the efficiency scenario. This section highlights the net changes Virginia's economy will experience as the result of our efficiency scenario.

Changes in Virginia's electricity production patterns from the efficiency scenario in comparison to the reference case are summarized in Table F.1, for the selected years 2010, 2015, 2020 and 2025. Again, these patterns are driven by the energy efficiency policy initiatives outlined in the policy analysis. Note that in comparison to the reference case the efficiency scenario rises/falls etc.

Table F.1. Changes in Virginia Electricity Production and Financial Impacts from Energy Efficiency Policy Scenario: 2010, 2015, 2020 & 2025

(Millions of 2006 $)*	2010	2015	2020	2025
Annual Total Cost**	$187	$575	$676	$668
Savings Relative to Reference Case:				
Cumulative Savings (GWh)	1,144	9,957	19,892	27,914
Cumulative Savings (%)	1.0%	7.9%	14.6%	19.4%
(Millions of 2006 $)*				
Annual Consumer Outlays	$171	$698	$935	$947
Annual Electricity Savings***	$106	$866	$1,696	$2,448
Annual Price of Electricity Savings***	$34	$312	$613	$681
Annual Net Consumer Savings	-$31	$480	$1,374	$2,182
Cumulative Net Energy Savings	-$69	$1,091	$5,673	$15,189

* 'Annual' refers to the given benchmark year, 'Cumulative' is the sum total from previous years begging with 2008.
**Annual total costs include administrative costs to run programs, incentives provided to consumers, and investments in energy efficiency devices (investments are from both utilities and consumers).
***Annual Electricity Savings is the amount of electricity that consumers save and its associated value in lowered energy bills. Annual Price of Electricity Savings are additional savings due to reductions in the *price* of electricity. Since consumers are using less electricity, demand falls, so then price.

The macroeconomic module of the DEEPER model traces how each set of policies transforms the Virginia economy in each year of the assessment period. Given the policy and program expenditures for the benchmark years, 2010, 2015, 2020 and 2025, the estimated changes in sectoral spending are provided in Table F.2. The module combined with estimated changes in sectoral spending then estimates the number of jobs and amount of wages each sector provides the Virginia economy. Although net jobs and wages were discussed in the body of this paper, additional values for the years 2010 and 2020 are provided in Table F.3.

Table F.2. Changes in Sector Spending (Millions of 2006 Dollars)

Sector	2010	2015	2020	2025
Agriculture	$0.0	$2.1	$8.7	$14.6
Oil and Gas Extraction	$0.1	$2.4	$11.0	$18.7
Coal Mining	$0.0	$0.0	$0.2	$0.3
Other Mining	$0.0	$1.0	$4.3	$7.3
Construction	-$25.0	-$354.4	$348.8	$499.7
Manufacturing	-$2.0	$25.4	$89.4	$147.6
Petroleum Refining	$0.2	$15.3	$66.9	$113.0
Electric Utility Services	$330.7	$178.5	-$289.3	-$468.2
Natural Gas Utility Services	-$0.1	$0.7	$2.3	$3.7
Transportation Other Public Utilities	-$3.5	-$6.8	-$4.8	-$0.2
Wholesale Trade	-$3.9	$55.1	$149.6	$235.2
Services	-$5.1	$218.2	$559.1	$865.2
Financial Services	-$1.3	-$10.1	-$50.7	-$39.2
Governmental Services	$3.5	$9.6	$15.7	$20.3

Table F.3. Economic Impact of Energy Efficiency Investment in Virginia: 2010, 2015, 2020 & 2025

Macroeconomic Impacts	2010	2015	2020	2025
Jobs (Actual)	964	675	7,392	9,820
Wages (Million $2006)	66	63	401	583
GSP (Million $2006)	216	202	628	882

There are other support spreadsheets as well as routines in visual basic programming that support the automated generation of model results and reporting. For more detail on the model assumptions and economic relationships, please refer to the forthcoming model documentation (Laitner and McKinney 2008b). For a review of how an I-O framework might be integrated into other kinds of modeling activities, see Hanson and Laitner (2007). While not an equilibrium model we borrow from some key concepts of mapping technology representation into DEEPER using the general scheme outlined in Laitner and Hanson (2007).