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FILED
AUG 30 2013
Clerk's Office
N.C. Utilities Commission

VIA UPS OVERNIGHT

August 29, 2013

Mrs. Gail L. Mount, Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, North Carolina 27603-5918

AG (no conf) — o — Full Dist.

Re: Integrated Resource Plan of Dominion North Carolina Power
Docket No. E-100, Sub 137

Dear Ms. Mount:

Pursuant to §§ 62-2 and 62-110.1 of the North Carolina General Statutes ("NCGS") and Rule R8-60(h)(2) of the Rules and Regulations of the North Carolina Utilities Commission (the "Commission"), Virginia Electric and Power Company d/b/a Dominion North Carolina Power (the "Company") encloses for filing with the Commission the **Public** version of the update to its Integrated Resource Plan for 2013 (the "2013 Plan").

Enclosed with the filing of this 2013 Plan are the public (redacted) versions of the NC IRP Addenda 1, 2 and 3. "NC Addendum 1" is the public (redacted) version of the Company's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plan, which is being filed pursuant to Rules R8-60(h)(4) and R8-67(b).

"NC IRP Addendum 2" contains pages 422, 423, 424, 425, 426 and 427 of the Company's most recently-filed Federal Energy Regulatory Commission ("FERC") Form 1 and is being provided with the 2013 Plan pursuant to Rule R8-62(p)(1). Information contained in NC IRP Addendum 2 is public.

"NC IRP Addendum 3" contains the public version of the Company's FERC Form 715.

In accordance with Ordering Paragraph (3) of the Commission's June 3, 2013 Order Granting in Part and Denying in Part Motion for Disclosure, the Company has reviewed its 2009 REPS Compliance Plan filed in Docket No. E-100, Sub 124, and, as no information contained in that filing was designated confidential qualifying as "trade secrets" under NCGS § 66-52(3), there is no information to disclose as no longer requiring such designation.

This 2013 Plan is also being filed with the Virginia State Corporation Commission pursuant to § 56-597 of the Code of Virginia. North Carolina and Virginia have similar requirements for integrated resource plan filings, but each requires its biennial filing in alternate years. Pursuant to Rule R8-60(h)(2), this annual update report contains an updated 15-year forecast of the items described in Rule R8-60(c)(1), as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.

Included with this filing letter is an index identifying the provisions of the Commission's integrated resource planning requirements under prior Commission orders and Rules R8-67, R8-62(p) with the corresponding sections of the 2013 Plan.

Pursuant to Ordering Paragraph (5) of the Commission's July 9, 2007 Order Approving Integrated Resource Plans issued in Docket No. E-100, Sub 109, the Company will meet with the Public Staff within 30 days of the filing date to discuss detailed information concerning its transmission line inter-tie capabilities, transmission line loading constraints, and planned new construction and upgrades within their respective control areas for the planning period under consideration.

In accordance with NCGS § 132-1.2 and Ordering Paragraph (7) of the Commission's July 9, 2007 Order Approving Integrated Resource Plans issued in Docket No. E-100, Sub 109, the Company has redacted the confidential information from this Public version of the entire filing, including the 2013 Plan and addenda, as appropriate, and separately files this public (redacted) version for review by the public. The Confidential version of this filing is being submitted confidential filed under seal contemporaneously with the Commission under separate cover, and the Company respectfully requests that the Commission treat the information in that filing as confidential filed under seal and protect it from public disclosure pursuant to NCGS § 132-1.2 and Rule R8-60(h)(5).

Therefore, please find enclosed for filing an unbound original and one (1) bound copy of the Public version of the 2013 Plan; including NC IRP Addenda 1, 2 and 3, with the confidential information redacted.

Please do not hesitate to contact me if you have any questions. Thank you for your assistance in this matter.

Sincerely,

Horace P. Payne

Horace P. Payne, Jr.
Senior Counsel

Enclosures

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AUG 30 2013
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N.C. Utilities Commission

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[1] Order Approving 2008 and 2009 Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Subs 118, 124 (August 10, 2010)

[2] Order Approving 2010 Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 128 (October 26, 2011)

[3] Order Approving 2011 Annual Updates to 2010 Integrated Resource Plans and 2011 REPS Compliance Plans, Docket No. E-100, Sub 128 (May 30, 2012)

[4] Order Approving Integrated Resource Plans, Docket No. E-100, Sub 109 (July 9, 2007)

[5] Order Denying Rulemaking Petition, Docket No. E-100, Sub 133 (October 30, 2012)

[6] Order Granting in Part and Denying in Part Motion for Disclosure, Docket No. E-100, Sub 137 (June 3, 2013)

[7] Order Adopting Integrated Resource Plans, Docket No. E-100, Sub 84 (June 21, 2000)

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Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Public Version

Case No. PUE-2013-00088
Docket No. E-100, Sub 137

Filed: August 30, 2013

DOMINION VIRGINIA POWER'S AND DOMINION NORTH CAROLINA POWER'S 2013 REPORT OF ITS INTEGRATED RESOURCE PLAN

LIST OF ACRONYMS

Acronym	Acronym Meaning
2012 Plan	2012 Integrated Resource Plan
2013 Plan	2013 Integrated Resource Plan
AC	Alternating Current
AMI	Advanced Metering Infrastructure
ATC	Available Transfer Capability
BOEM	Bureau of Ocean Energy Management
BTMG	Behind-the-Meter Generation
Btu	British Thermal Unit
CAP	President's Climate Action Plan
CAPP	Central Appalachian
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CDG	Commercial Distributed Generation
CFB	Circulating Fluidized Bed
CFL	Compact Florescent Light
CO_2	Carbon Dioxide
COL	Combined Construction Permit and Operating License
Company	Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power
CPCN	Certificate of Public Convenience and Necessity
CS	Curtailable Service
CSP	Concentrating Solar Power
CT	Combustion Turbine
DC	Direct Current
DG	Distributed Generation
DOE	Department of Energy
DOM LSE	Dominion Load Serving Entity
DOM Zone	Dominion Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization
DSI	Dry Sorbent Injection
DSM	Demand-Side Management
EEP	Energy Extraction Partners, LLC
EM&V	Evaluation, Measurement, and Verification
EP&S	Economic Power & Steam Generation, LLC
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESBWR	Economic Simplified Boiling Water Reactor
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
Fluor	Fluor Enterprises, Inc.
GEH	GE-Hitachi Nuclear Energy Americas LLC
GHG	Greenhouse Gas
GSP	Gross State Product
GWh	Gigawatt Hour(s)
Hg	Mercury
HVAC	Heating, Ventilating, and Air Conditioning
ICF	ICF International, Inc.
IDR	Interval Data Recorder
IGCC	Integrated-Gasification Combined-Cycle
IRM	Installed Reserve Margin
IRP	Integrated Resource Planning
KEMA	DNV KEMA Energy & Sustainability
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt Hour
LMP	Locational Marginal Pricing

Acronym	Acronym Meaning
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MW	Megawatt(s)
MWh	Megawatt Hour(s)
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
North Anna 3	North Anna Unit 3
NO_x	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NUG	Non-Utility Generation or Non-Utility Generator
O&M	Operation and Maintenance
ODEC	Old Dominion Electric Cooperative
ODU	Old Dominion University
OEM	Original Equipment Manufacturers
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection, L.L.C.
Plan	2013 Integrated Resource Plan
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
REC	Renewable Energy Certificate
REPS	Renewable Energy and Energy Efficiency Portfolio Standard (NC)
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RPM	Reliability Pricing Model
RPS	Renewable Energy Portfolio Standard (VA)
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	Virginia State Corporation Commission
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction
SG	Standby Generation
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SPP	Solar Partnership Program
SRP	Stakeholder Review Process
STAP	Short-Term Action Plan
Strategist	Strategist Model
T&D	Transmission and Distribution
TRC	Total Resource Cost
UCT	Utility Cost Test
Va. Code	56-599 of the Code of Virginia
VACAR	Virginia-Carolinas Reliability Agreement
VCHEC	Virginia City Hybrid Energy Center
VOW	Virginia Offshore Wind Coalition
VOWDA	Virginia Offshore Wind Development Authority
WEA	Wind Energy Area

INTRODUCTION

Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power (collectively, the "Company") files its 2013 Integrated Resource Plan ("2013 Plan" or "Plan") in accordance with § 56-599 of the Code of Virginia ("Va. Code") and the Virginia State Corporation Commission's ("SCC") guidelines issued on December 23, 2008, as well as § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of the North Carolina Utilities Commission's ("NCUC") Rules and Regulations.

The Company has long believed in the importance of a balanced blend of cost-effective supply-side and demand-side resources to meet its customers' needs, which continue to grow in its Virginia and North Carolina service territories. The Company's long-range forecast indicates that customer demand for energy in the Dominion Load Serving Entity ("DOM LSE"), the area in which the Company serves, will continue to grow during the planning period, with peak demand and overall energy use increasing by average annual rates of 1.6% and 1.7%, respectively. A balanced approach will help the Company meet this growing demand while protecting customers from a variety of potentially negative impacts, including changing regulatory requirements, commodity price volatility, and reliability concerns based on overreliance on any one fuel source. This approach reflects the legislative and regulatory mandates of both Virginia and North Carolina. Va. Code § 56-597.3 requires that the integrated resource plan "reflect a diversity of electric generation supply and cost-effective demand reduction contracts." Similarly, Rule R8-60 of the NCUC directs that the integrated resource plan contain "a comprehensive analysis of all resource options (supply- and demand-side)."

To assess the uncertainties and risks presented by external market, regulatory and environmental factors, the Company developed six alternative plans representing plausible future paths for meeting customer needs, subjecting them to 16 different scenarios and sensitivities and one basecase. The 2013 Plan also reflects the Company's most current planning assumptions such as fuel prices, load growth, economic conditions, and equipment costs. Additionally, as with other integrated resource plans, the 2013 Plan is not a request for approval of any particular resource, nor is it a commitment to any particular resource.

Options Presented in the 2013 Plan

Through the integrated resource planning ("IRP") process, the Company has assessed a range of options for meeting customer demand in an environment that presents considerable uncertainty, including fuel prices, federal regulation of greenhouse gas ("GHG"), and other potential regulatory mandates. Based on these assessments, the Company recommends a strategic path forward that continues to follow the resource expansion of the Base Plan, designed using least-cost planning methods, and concurrently continues forward with reasonable development efforts of the additional resources of a more fuel diverse plan (the "Fuel Diversity Plan"), which includes nuclear, wind, and increased amounts of solar technologies. Collectively, this recommended path forward is the 2013 Plan.

Under current planning assumptions, the resources included in the Fuel Diversity Plan cause it to be at a higher cost than the Base Plan. However, the Company believes the low or zero-emissions components of the Fuel Diversity Plan could well be needed, by both the Company and its customers, to deal with future uncertainties, particularly federal legislation or regulation restricting GHGs. Therefore, the Company strongly recommends that it continue to evaluate and develop this broader array of resources.

New Renewable Resources Common to Both the Base Plan and the Fuel Diversity Plan

The Base Plan and the Fuel Diversity Plan have many elements in common, including adding energy and capacity from renewable resources to the Company's generation portfolio.

Both the Base Plan and Fuel Diversity Plan continue the Company's extensive use of biomass. Each Plan calls for the addition of a 20 megawatt ("MW") biomass facility operated by a non-utility generator ("NUG"), Economic Power & Steam Generation, LLC, ("EP&S") by 2015. This unit would join four Company-operated facilities using wood waste, including the 83 MW Pittsylvania County Power Station and three coal-to-wood waste conversions, 51 MW each, in Altavista, Southampton County, and Hopewell.

Additionally, the Company's Virginia City Hybrid Energy Center ("VCHEC") is equipped to co-fire with wood waste biomass, and will gradually increase its use of that resource. By 2020, 10 percent, or 60 MW, of the plant's capacity is expected to be derived from biomass fuel.

Both Plans also include a 15 MW project by a NUG, Energy Extraction Partners, LLC, ("EEP") powered by solid waste. Further, both Plans include 50 MW of solar generation to be provided by one or more NUGs by 2015, as well as 24 MW from the first phase of the Company's Solar Partnership Program (formerly called the Community Solar Program), which calls for installation of Company-owned solar arrays on rooftops and other spaces rented from customers at sites distributed throughout the service area.

The Base Plan

Representing the least-cost path forward for the Company, using current assumptions, the Base Plan includes demand-side management programs that are expected to reduce the system summer peak demand for electricity by 544 MW by 2028. Additionally:

- The Base Plan calls for the Company to continue to take advantage of the economical supplies of power available to it in the wholesale market operated by PJM, with net market purchases averaging 127 MW of capacity and 12% of energy supplied to customers annually during the planning period (2014 - 2028).
- The Base Plan also includes two major combined-cycle ("CC") natural gas generation projects approved by the SCC, including the 1,337 MW Warren County Power Station, scheduled to be operational by 2015, and the 1,375 MW Brunswick County Power Station, scheduled to be operational by 2016. It also includes the repowering of both

units at Bremo Power Station from coal to natural gas, with a combined output of 227 MW, to be available by 2014. The conversion project is pending before the SCC.

- The Base Plan incorporates the effect of the retirements of 918 MW of coal-fired capacity at Chesapeake Energy Center and Yorktown Power Station. The Company had determined that continued operation of the Chesapeake and Yorktown coal units would have required expensive environmental compliance controls that would not be cost-effective for the Company's customers. The six units are scheduled for shutdown by 2015.
- Additionally, the Base Plan calls for installation of advanced environmental controls on two large oil-fired units at Yorktown Power Station and Possum Point Power Station, with a combined capacity of more than 1,600 MW. The retrofits will be completed by 2018. These units operate primarily during periods of peak demand, such as extremely hot summer days.
- However, for major future generation projects, the Base Plan makes almost exclusive use of one fuel source: natural gas. It includes two additional CCs, with a total capacity of 2,750 MW, and three additional banks of combustion turbines ("CTs"), with a total capacity of 1,371 MW. These facilities would begin operation from 2019 to 2027.

<u>The Fuel Diversity Plan</u>

As noted, the Fuel Diversity Plan has many elements in common with the Base Plan, but over the longer term, provides additional alternatives for meeting future customer needs and reduces the Company's reliance on natural gas as the fuel source for expansion of the generation fleet. The Fuel Diversity Plan calls for only one additional CC beyond the Warren and Brunswick facilities, now under construction, with the third project operational by 2019. The Fuel Diversity Plan also places a greater reliance on generation sources with little or no GHGs, a characteristic that could become extremely important in a lower-carbon future. While the Base Plan outlines a plausible, least-cost path forward for dealing with the increasing demand for electricity, the Company will, at a minimum, continue to evaluate and develop additional alternatives for renewable energy and nuclear-powered generation described in the Fuel Diversity Plan. Some of the differing characteristics of this plan are detailed below.

<u>Solar</u>

The Fuel Diversity Plan includes additional generating resources of approximately 220 MW (nameplate) powered by solar energy by 2024. This includes several new Company-owned photovoltaic ("PV") installations. Solar PV costs have declined in recent years, but solar energy still represents a highly variable resource for an electric power system and cannot be dispatched by the utility. Therefore, such units do not contribute as much to peak load and reserve requirements as conventional resources. However, continuing technological development, in which the Company intends to participate, may allow solar to become a more reliable resource in the future.

Wind

Wind is one of the fastest growing generation resources in the United States, and the Company's Fuel Diversity Plan includes three onshore wind units in western Virginia and a demonstration facility off the Virginia coast. While onshore wind resources are limited in the Mid-Atlantic area, the Company has identified three sites in western Virginia for potential wind development, with a combined capacity of 247 MW (nameplate) that would enter service from 2022 to 2024. Due to the highly variable nature of the resource, these resources may not be available to meet peak demands and generally make capacity contributions at much lower levels than their nameplate ratings.

Offshore wind is widely recognized as a resource with great potential. The technology currently faces significant barriers, due to complex and costly installation and maintenance requirements in a hostile marine environment. However, the Company is leading efforts to develop offshore wind and overcome these barriers, and a 12 MW (nameplate) Offshore Wind Demonstration Project facility is included in the Fuel Diversity Plan, with operation scheduled by 2018. The Company and several partners are collaborating on the project, which would involve construction of two 6 MW Alstom turbines at a test site off the Virginia coast. The Company-led project received a $4 million U.S. Department of Energy ("DOE") grant for initial design, engineering and permitting in December 2012, and is a finalist for an additional $47 million federal grant.

The Company has also announced that it will participate in a September 2013 auction conducted by the U.S. Bureau of Offshore Energy Management ("BOEM"). Through the process, BOEM will lease an 112,400-acre area about 24 miles off the Virginia coast for wind energy development. Initial estimates indicate that the area could accommodate 1,500 to 2,000 MW of wind-powered capacity, but actual construction of such facilities must await technological advances that would reduce costs.

Nuclear Energy

The Company believes that nuclear energy, capable of producing large amounts of clean baseload power with little or no GHG emissions, will continue to play a significant role in its generation mix throughout the planning period and beyond. Nuclear construction remains time-consuming, with various permits for design, location and operation required by government agencies, but once operational, nuclear facilities have the lowest fuel cost of any dispatchable baseload generation option.

Therefore, the Fuel Diversity Plan reflects the Company's continued development activities that preserve the ability to construct a third reactor at its North Anna Power Station in Virginia. North Anna Unit 3 ("North Anna 3") would have a generating capacity of approximately 1,453 MW and be powered by economic simplified boiling water reactor ("ESBWR") technology developed by GE-Hitachi Nuclear Energy Americas LLC ("GEH").

It must be emphasized that the Company has not committed to building this unit. It expects to make a final decision once it receives its Combined Operating License ("COL") for the project from the U.S. Nuclear Regulatory Commission ("NRC"). If the Company decides to proceed, the Fuel Diversity Plan has North Anna 3 reaching commercial operation in October 2024, which is the unit's earliest possible online date.

Conclusions

The Company's 2013 Plan presents several plans for meeting expected customer demand growth and meeting reserve requirements in a cost-effective manner. The 2013 Plan presents a Base Plan that, given current conditions, represents the least-cost path forward for dealing with increasing demand but relies almost exclusively on natural gas for major expansions of generating capacity in the future. As an alternative, the 2013 Plan presents a Fuel Diversity Plan, which contains additional zero and low-emission options that might become necessary given stricter federal regulation of GHG. The Company, therefore, will follow the resource expansion of the Base Plan and concurrently continue forward with reasonable development efforts of the additional resources of the Fuel Diversity Plan. These continued development activities, particularly for nuclear and renewable energy, will preserve the Company's ability to implement these alternatives should future conditions warrant.

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Chapter 1 | Executive Summary

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTEGRATED RESOURCE PLAN OVERVIEW

On August 31, 2012, the Company filed its 2012 Integrated Resource Plan ("2012 Plan") with the SCC (Case No. PUE-2012-00099) and the NCUC (Docket No. E-100, Sub 137). On October 16, 2012, the SCC issued its Final Order finding that, among other things, the 2012 Plan complies with applicable law and guidelines and accepting it for filing. The Company's 2012 Plan remains pending before the NCUC.

The 2013 Plan was prepared for the DOM LSE, and represents the Company's service territories in the Commonwealth of Virginia and the State of North Carolina, which are part of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization ("RTO").

The Company's objective in developing the 2013 Plan was to identify the mix of resources necessary to meet our customers' future energy and capacity needs in an efficient and reliable manner at the lowest reasonable cost, while considering future uncertainties. The Company's options for meeting these future needs are: i) supply-side resources, ii) demand-side resources, and iii) market purchases.

The 2013 Plan is a long-term planning document and should be viewed in that context. It should be noted that provisions of Virginia and North Carolina law result in the Company preparing an integrated resource plan every year. Inclusion of a project in any given year's plan is not a commitment to construct a particular project or a request for approval of a particular project. Conversely, not including a specific project in a given year's plan does not mean that the Company will not choose to include that project in subsequent regulatory filings.

The Company used the Strategist model ("Strategist"), a utility modeling and resource optimization tool, to develop its 2013 Plan over a 25-year period, beginning in 2014 and continuing through 2038 ("Study Period"), using 2013 as the base year. For purposes of this Plan, the Company displays text, numbers, and appendices for a 15-year period from 2014 to 2028 ("Planning Period"). The 2013 Plan is based on the Company's current assumptions regarding load growth, commodity price projections, Demand-Side Management ("DSM") programs, and many other regulatory and market developments that may occur during the Study Period.

The 2013 Plan includes sections on load forecasting (Chapter 2), existing and proposed resources (Chapter 3), planning assumptions (Chapter 4), and future resources (Chapter 5). Additionally, the 2013 Plan includes Chapter 6, titled "Development of the Integrated Resource Plan," which defines the IRP process and outlines several alternative plans that were compared by weighing the costs and benefits of those plans using a variety of sensitivities and scenarios. This analysis allowed the Company to examine alternate plans given industry uncertainties, such as environmental regulations, resource mix, and commodity prices. The 2013 Plan also contains a Short-Term Action Plan ("STAP") (Chapter 7), which discusses the Company's specific actions currently underway to support the 2013 Plan over the next five years (2014 - 2018).

Starting in 2010, the Company initiated its Stakeholder Review Process ("SRP"), which is designed to be a forum to inform stakeholders about the IRP process and to provide more specific information about the Company's planning process, including IRP and DSM initiatives. The SCC also directed the Company to coordinate with interested parties in sharing DSM program Evaluation, Measurement and Verification ("EM&V") results and in developing future DSM program proposals. Several SRP suggestions have been incorporated into the Company's new DSM Program approval filing made coincident with the 2013 Plan in Case No. PUE-2013-00072. The Company is committed to continuing the SRP and expects the next SRP meeting to occur in the fall of 2013.

1.2 COMPANY DESCRIPTION

The Company, headquartered in Richmond, Virginia, currently serves approximately 2.4 million electric customers covering approximately 30,000 square miles in Virginia and North Carolina. The Company's regulated electric portfolio consists of 19,453 MW of generation capacity, including approximately 1,747 MW of NUG resources, over 6,400 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and more than 56,919 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia, North Carolina and West Virginia. In May 2005, the Company became a member of PJM, the operator of the wholesale electric grid in the Mid-Atlantic region of the United States. As a result, the Company transferred operational control of its transmission assets to PJM.

The Company has a diverse mix of generating resources consisting of Company-owned nuclear, fossil, hydro, pumped storage, biomass and solar facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market.

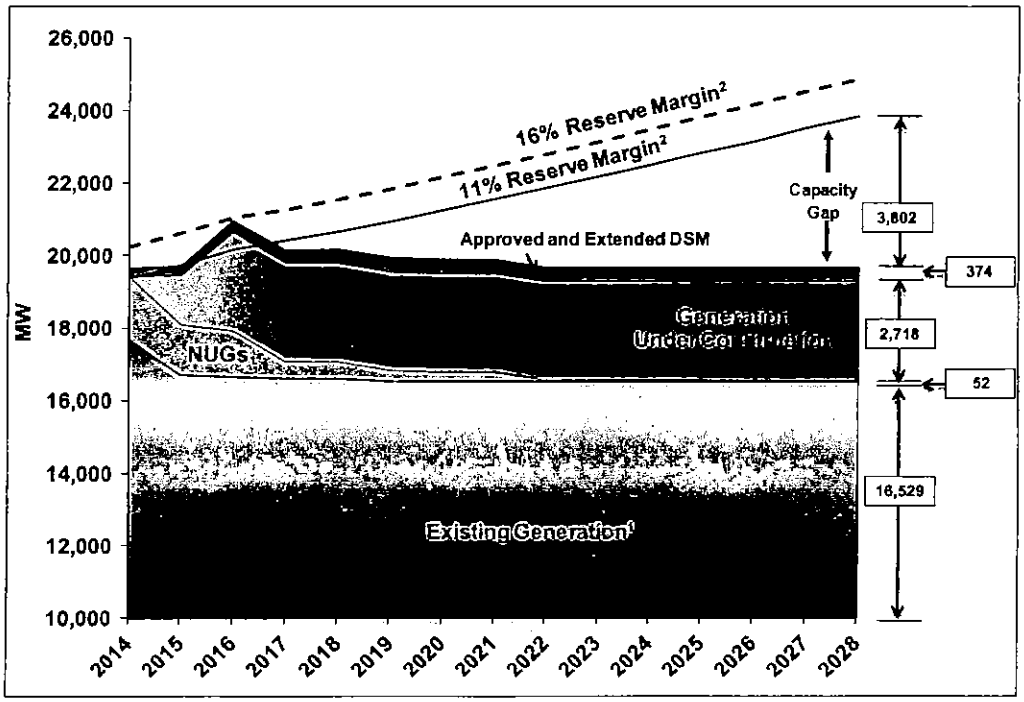
1.3 2013 INTEGRATED RESOURCE PLANNING PROCESS

In order to meet future customer needs at the lowest reasonable cost while maintaining reliability, the Company must take into consideration the uncertainties and risks associated with the energy industry. Uncertainties assessed in the 2013 Plan include:

a) load growth in the Company's service territory;
b) effective and anticipated U.S. Environmental Protection Agency ("EPA") regulations concerning air, water, and solid waste constituents, as shown in Figure 3.1.3.1;
c) the President's Climate Action Plan;
d) fuel prices;
e) cost and performance of energy technologies;
f) retirements of non-Company controlled units that may impact available purchase power volumes; and
g) meeting renewable requirements.

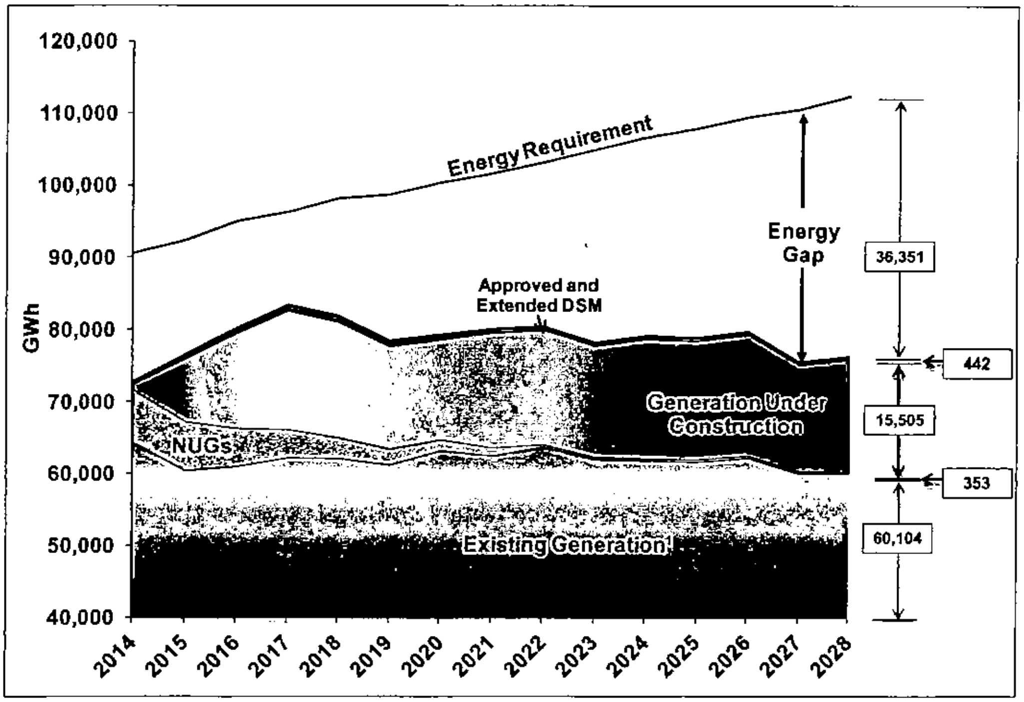
The Company has developed a comprehensive IRP process that evaluates various supply- and demand-side alternatives, considering acceptable levels of risk and maintains the option to develop a diverse mix of resources for the benefit of its customers. Various planning groups throughout the Company provided input and insight into evaluating all viable options, including existing generation, DSM programs, and new (both traditional and alternative) resources to meet the growing demand in the Company's service territory. The IRP process began with the development of the Company's long-term load forecast, which indicates that over the Planning Period, the DOM LSE is expected to have annual increases in future peak and energy requirements of 1.6% and 1.7%, respectively. Collectively, these elements assisted in determining updated capacity and energy requirements as illustrated in Figure 1.3.1 and Figure 1.3.2.

Figure 1.3.1 CURRENT COMPANY CAPACITY POSITION (2014 – 2028)



Note: *The values in the boxes represent total capacity in 2028. One MW can serve the peak demands of about 250 homes.*
1) *Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.*
2) *See Section 4.2.2.*

Figure 1.3.2 CURRENT COMPANY ENERGY POSITION (2014 – 2028)



Note: *The values in the boxes represent total energy in 2028.*
1) *Accounts for unit retirements and rating changes to existing units in the Plan.*

1.4 2013 PLAN

To assess the uncertainty and risks associated with external market and environmental factors, the Company developed six alternative plans representing plausible future paths the Company could follow to meet the future electric power needs of its customers. The Company evaluated the six alternative plans using 16 scenarios and sensitivities and one basecase, as discussed in Chapter 6. Based on this evaluation, the Company selects a going-forward strategic plan that contains an optimal mix of supply- and demand-side options to meet expected future customer needs at the lowest reasonable cost. As with any strategic plan, the Company will update its future plans to incorporate new information as it becomes known.

For this 2013 Plan, the Company recommends a path forward that continues to follow an expansion consistent with Plan A: Base Plan, which follows least-cost methodology given basecase assumptions, and concurrently continues forward with reasonable development efforts of the additional resources identified in Plan B: Fuel Diversity Plan (Plan A and B are specified in Chapter 6). Collectively, this recommended path forward is the 2013 Plan.

The electric power industry has been, and continues to be, dynamic in nature with rapidly changing developments and regulatory challenges. The Company expects that these dynamics will continue into the future and will be further complicated by societal megatrends including national security considerations (which include infrastructure security) and climate change focused laws and regulations. Therefore, it is prudent for the Company to preserve reasonable development options available to it in order to be able to respond to the future market, regulatory, and industry changes that are likely to occur in some form, but are difficult to predict at the present time. Consequently, the Company recommends (and plans for), at a minimum, continued development of the additional supply-side resources included in Plan B: Fuel Diversity Plan identified in Chapter 6. The Company will also continue with reasonable development of other emerging technologies.

Plan A: Base Plan, in addition to traditional supply- and demand-side options, includes a 20 MW biomass NUG, EP&S, and a renewable 15 MW solid waste NUG, EEP, both in 2015. The Base Plan also includes a 50 MW (nameplate) solar, to be provided by one or more, NUGs (referenced as "solar NUG") and 24 MW (nameplate) of solar capacity (30 MW direct current ("DC")) from the Solar Partnership Program ("SPP") (approved in SCC Case No. PUE-2011-00117). Previously coal-fired Altavista, Southampton, and Hopewell Power Stations (153 MW total) will be repowered with primarily wood waste biomass by the end of 2013 (Altavista achieved commercial operations on July 12, 2013).

In addition to the resources identified in the Base Plan, Plan B: Fuel Diversity Plan provides the most reliable baseload, near emissions-free energy over the long-term by including an additional nuclear unit at the Company's North Anna Power Station, as well as 247 MW (nameplate) of onshore wind, 20 MW (nameplate) brownfield solar ("solar tag"), 200 MW (nameplate) solar, and the 12 MW (nameplate) Offshore Wind Demonstration Project. Nuclear units, despite their high upfront capital costs, have very low long-term fuel costs (with little correlation to fossil fuel commodity prices), little to no air emissions, and a long track record of delivering reliable baseload energy and improving fleet diversity. The Company's customers today benefit substantially from the Company's prior investments in the four nuclear units, at North Anna and Surry.

Both Plan A: Base Plan and Plan B: Fuel Diversity Plan are displayed in Figures 1.4.1(a) and 1.4.1(b), respectively.

Figure 1.4.1(a) 2013 BASE PLAN

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2014		SPP		BR3 – Gas BR4 – Gas		Approved & Extended DSM Proposed & Future DSM
2015	Warren	EEP / SLR NUG SPP / EP&S			CEC 1-4 YT 1-2	
2016	Brunswick					
2017						
2018			PP5 – SNCR YT3 – SNCR			
2019	CC					
2020						
2021	CT					
2022	CT					
2023	CT					
2024						
2025						
2026						
2027	CC					
2028						

Figure 1.4.1(b) 2013 FUEL DIVERSITY PLAN

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2014		SPP		BR3 – Gas BR4 – Gas		Approved & Extended DSM Proposed & Future DSM
2015	Warren	EEP / SLR NUG NUG SPP / EP&S			CEC 1-4 YT 1-2	
2016	Brunswick					
2017		SLR TAG / SLR				
2018		OFFD / SLR	PP5 – SNCR YT3 – SNCR			
2019	CC	SLR				
2020		SLR TAG / SLR				
2021		SLR				
2022	CT	WND				
2023		WND				
2024		WND				
2025	North Anna 3[2]					
2026						
2027	CT					
2028	CT					

***Key:** Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or repower by natural gas; Retire: Remove a unit from service; BR: Bremo; Brunswick: Brunswick County Power Station; CEC: Chesapeake Energy Center Unit; CC: Combined-Cycle; CT: Combustion Turbine (2 units); EEP: Energy Extraction Partners, LLC; EP&S: Economic Power & Steam Generation, LLC; OFFD: Offshore Wind Demonstration Project; North Anna 3: North Anna Unit 3; PP5: Possum Point Unit 5; SNCR: Selective Non-Catalytic Reduction; SLR: Generic Solar; SLR NUG: Solar NUG; SLR TAG: Solar Tag; SPP: Solar Partnership Program; Warren: Warren County Power Station; WND: Onshore Wind; YT: Yorktown Unit.*

***Note: 1)** DSM capacity savings continue to increase throughout the Planning Period.*

***2)** Earliest possible in-service date for North Anna 3 is October 2024, which is reflected as a 2025 capacity resource.*

Plan A: Base Plan includes:

Demand-Side Resources:

a) approved and extended DSM programs reaching approximately 374 MW by 2028; proposed and future DSM programs reaching approximately 170 MW by 2028;

Changes to Existing Resources:

b) the repowering of Bremo Power Station Units 3 and 4 from coal to natural gas totaling 227 MW by 2014;

Generation Under Construction:

c) Warren County Power Station, of approximately 1,337 MW of natural gas-fired combined-cycle capacity by 2015;
d) Brunswick County Power Station (natural gas), of approximately 1,375 MW by 2016;
e) Solar Partnership Program, consisting of 7 MW of firm capacity (24 MW nameplate) of solar distributed generation by 2015;

Generation Under Development:

f) conventional generation resources including one combined-cycle ("CC") totaling approximately 1,375 MW;

Potential Generation:

g) conventional generation resources including one CC unit, totaling approximately 1,375 MW and three CT[1] plants totaling approximately 1,371 MW;

NUG and Market Purchases:

h) NUG capacity and energy under contract including a new renewable EEP NUG of 15 MW and a new biomass EP&S NUG of 20 MW, both in 2015;
i) 19 MW firm capacity (50 MW nameplate) solar NUG by 2015; and
j) PJM net market purchases which average approximately 127 MW of capacity and 12% of energy annually.

Plan B: Fuel Diversity Plan includes:

Demand-Side Resources:

a) approved and extended DSM programs reaching approximately 374 MW by 2028; proposed and future DSM programs reaching approximately 170 MW by 2028;

Changes to Existing Resources:

b) the repowering of Bremo Power Station Units 3 and 4 from coal to natural gas totaling 227 MW by 2014;

Generation Under Construction:

c) Warren County Power Station, of approximately 1,337 MW of natural gas-fired combined-cycle capacity by 2015;
d) Brunswick County Power Station (natural gas), of approximately 1,375 MW by 2016;

[1] All references regarding new CT units throughout this document refer to installation of a bank of two CT units.

e) Solar Partnership Program, consisting of 7 MW of firm capacity (24 MW nameplate) of solar distributed generation by 2015;

Generation Under Development:

f) North Anna 3 (nuclear), of approximately 1,453 MW by 2025 (earliest possible in-service date for North Anna 3 is October 2024, which is reflected as a 2025 capacity resource);
g) Offshore Wind Demonstration Project, which totals 2 MW firm capacity (12 MW nameplate) by 2018;
h) conventional generation resources including one CC totaling approximately 1,375 MW;
i) renewable resources of onshore wind providing 32 MW firm capacity (247 MW nameplate) by 2024, two 4 MW firm capacity (10 MW nameplate each) solar tags by 2017 and 2020, 77 MW (200 MW nameplate) solar by 2021;

Potential Generation:

j) conventional generation resources including three CTs, totaling approximately 1,371 MW;

NUG and Market Purchases:

k) NUG capacity and energy under contract including a new renewable EEP NUG of 15 MW and a new biomass EP&S NUG of 20 MW, both in 2015;
l) 19 MW firm capacity (50 MW nameplate) solar NUG by 2015; and
m) PJM net market purchases which average approximately 173 MW of capacity and 12% of energy annually.

The Fuel Diversity Plan incorporates a significant amount of renewable generation. The following table identifies the renewable resources included in the Base and Fuel Diversity Plans:

Figure 1.4.2 NEW RENEWABLE RESOURCES

Resource Name	Year	Type	Nameplate Capacity (MW)	Firm Capacity (MW)	Plan
Solar Partnership Program	2014	Distributed Solar	12	3.5	A, B
Solar Partnership Program	2015	Distributed Solar	12	3.5	A, B
Energy Extraction Partners, LLC	2015	Solid Waste	15	15	A, B
Economic Power & Steam Generation, LLC	2015	Biomass/Wood	20	20	A, B
Solar NUG	2015	Solar	50	19	A, B
Solar	2017	Solar	40	15	B
Solar Tag	2017	Solar	10	4	B
Solar	2018	Solar	40	15	B
Offshore Wind Demonstration Project	2018	Wind	12	2	B
Solar	2019	Solar	40	15	B
Solar	2020	Solar	40	15	B
Solar Tag	2020	Solar	10	4	B
Solar	2021	Solar	40	15	B
Wind 1	2022	Wind	120	16	B
Wind 2	2023	Wind	81	10	B
Wind 3	2024	Wind	46	6	B

Key: A: Plan A: Base Plan; B: Plan B: Fuel Diversity.

To meet the projected demand of electric customers and annual reserve requirements throughout the Planning Period, the Company has identified additional resources utilizing a balanced mix of supply- and demand-side resources and market purchases to fill the capacity gap shown in Figure 1.3.1. These resources are illustrated in Figures 1.4.3(a), 1.4.3(b), 1.4.4(a) and 1.4.4(b).

Figure 1.4.3(a) PLAN A: BASE PLAN – CAPACITY (2014 - 2028)

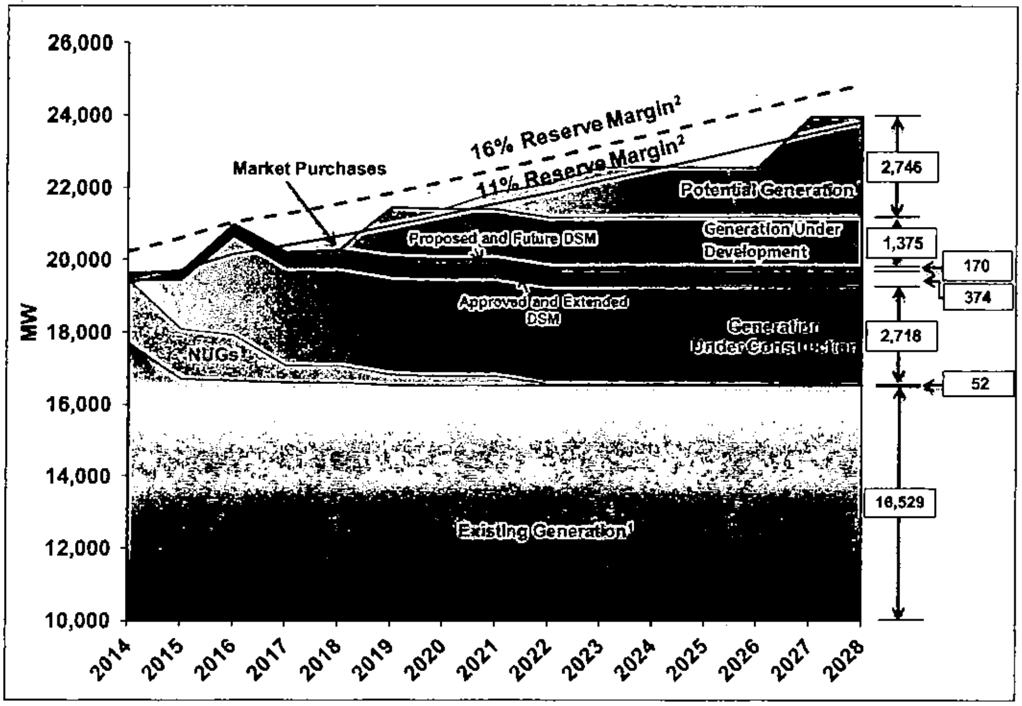
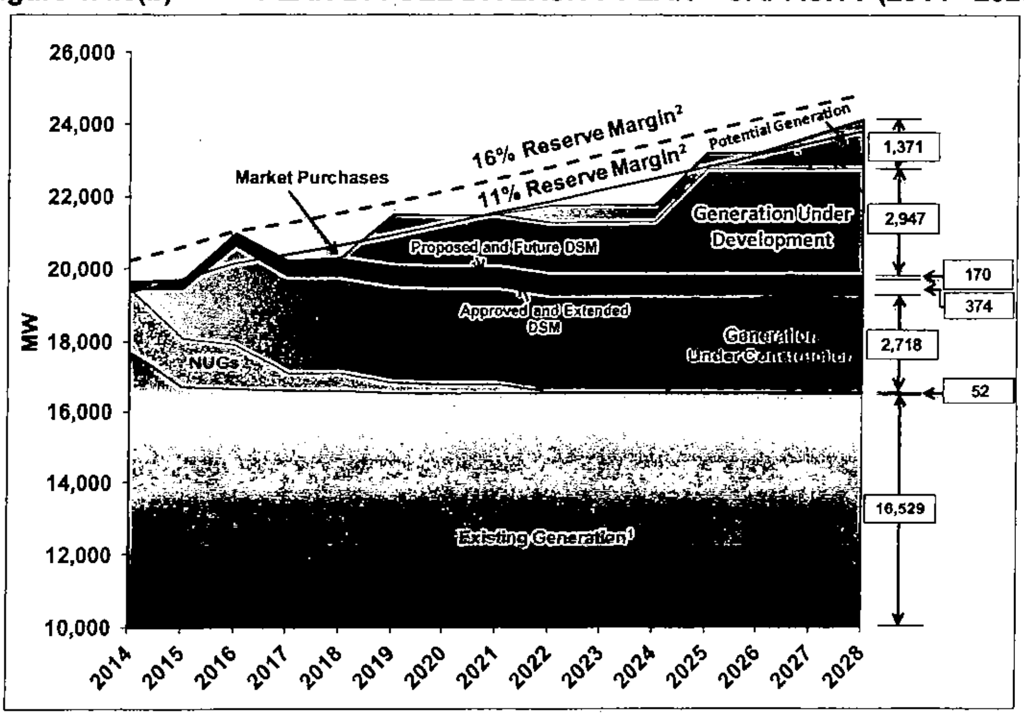


Figure 1.4.3(b) PLAN B: FUEL DIVERSITY PLAN – CAPACITY (2014 - 2028)



Note: *1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.*
2) See Section 4.2.2.

Figure 1.4.4(a) PLAN A: BASE PLAN – ENERGY PROJECTION (2014 – 2028)

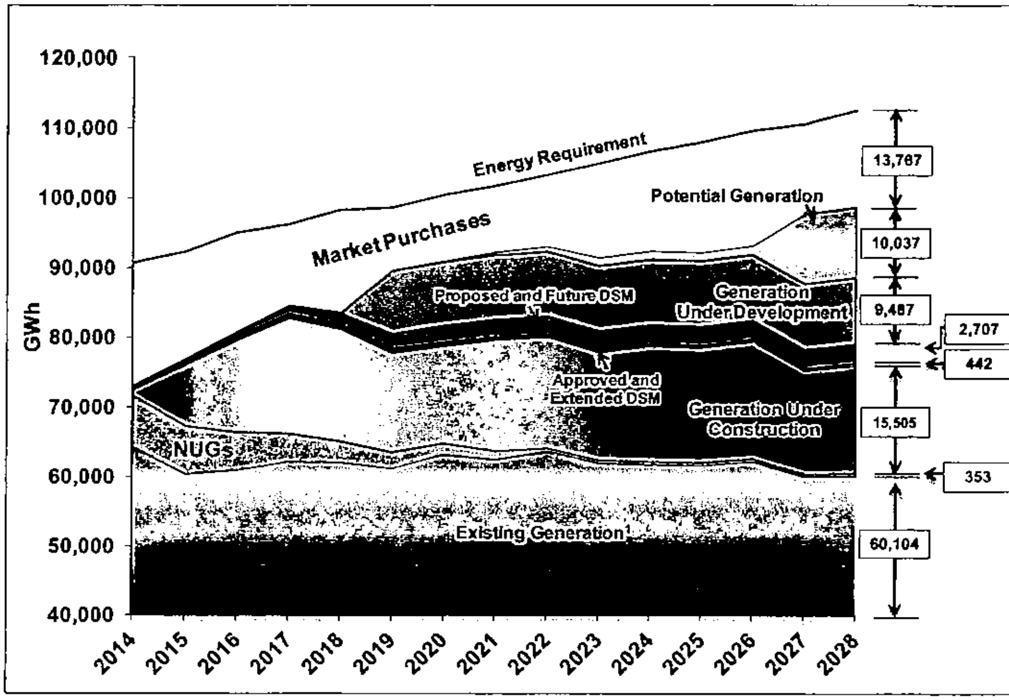
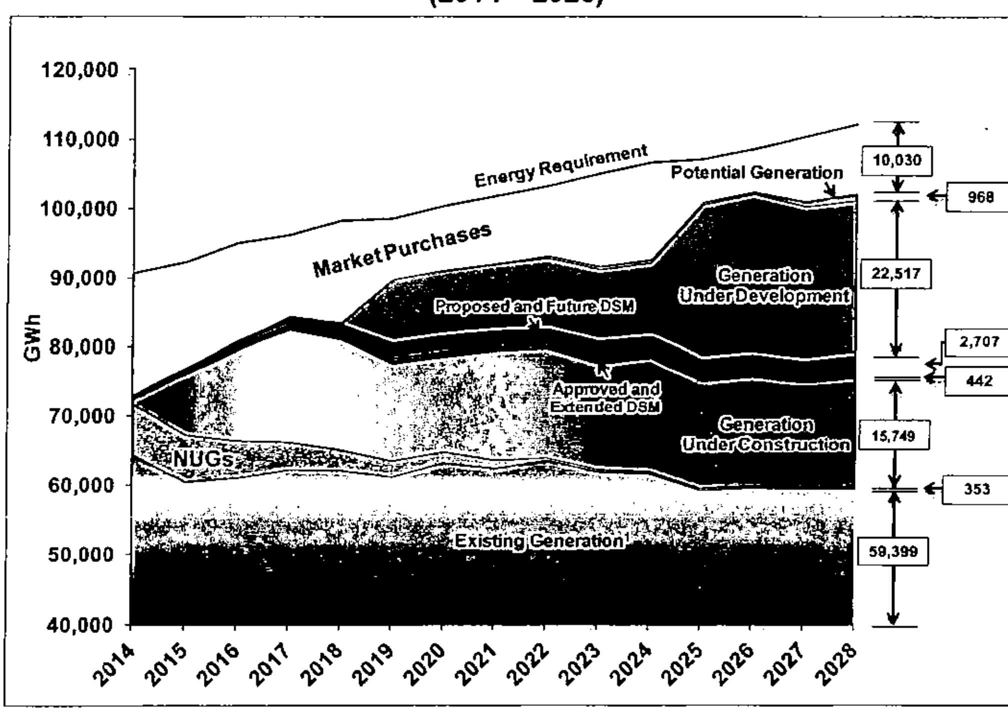


Figure 1.4.4(b) PLAN B: FUEL DIVERSITY PLAN – ENERGY PROJECTION (2014 – 2028)



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan.

The 2013 Plan balances the Company's commitment to operate in an environmentally responsible manner with its obligation to provide reliable and reasonably-priced electric service. The Company has established a strong track record of environmental protection and stewardship and has spent more than $1.8 billion since 1998 to make environmental improvements to its generation fleet. These improvements are projected to reduce emissions of key pollutants by more than 84% for Nitrogen Oxide ("NO_x"), 88% for mercury ("Hg"), and 94% for Sulfur Dioxide ("SO_2") by 2015.

Since numerous EPA regulations are effective and anticipated (as further shown in Figure 3.1.3.1), various alternatives had been analyzed with respect to the Company's environmentally "at risk" units. Coal-fired and/or oil-fired units that have limited environmental controls are considered at risk units. Coal-fired units that are environmentally controlled will continue to operate with relatively small additional expenses. Environmental compliance offers three options for at risk units: 1) retrofitting with additional environmental control reduction equipment, 2) repowering to biomass or natural gas, or 3) retiring the unit.

The impact of at risk units on the 2013 Plan is as follows:

Retrofit

a) 1,604 MW of heavy oil-fired generation installed with new Selective Non-Catalytic Reduction ("SNCR") controls at Possum Point Unit 5 and Yorktown Unit 3 by 2018

Repower

b) 227 MW of coal-fired generation repowered from coal to natural gas by 2014 at Bremo Units 3 and 4

Retire

c) 918 MW of coal-fired generation retired by 2015 at Chesapeake Energy Center Units 1-4 and Yorktown Units 1 and 2

The 2013 Plan positions the Company to address uncertainties associated with potential changes in market conditions and environmental regulations, while meeting future demand effectively through a balanced portfolio.

In June 2013, the President released a Climate Action Plan ("CAP") focusing on ways to meet the national GHG reduction goal of 17% from 2005 levels by 2020. Pursuant to the Presidential Memorandum issued in conjunction with the CAP, the EPA expects to re-propose the GHG New Source Performance Standards ("NSPS") for new sources by September 2013 and finalize the rule in a timely manner. The Presidential Memorandum also directed the EPA to propose a rule for reconstructed, modified and existing sources no later than June 2014, and issue a final rule no later than June 2015, to provide guidelines to the states to achieve the required GHG reductions. The Company currently cannot predict with certainty the direct or indirect financial impact on operations from these rule revisions, but believes the expenditures to comply with any new requirements could be material. As a result, the Company has included an Alternative Plan (Section 6.5) that reflects a plausible future path under the CAP.

The Company is also cognizant of global and U.S. policy trends towards low-emitting and/or non-emitting generating resource technologies. This recognition has been incorporated in the decision process of the 2013 Plan.

The Company has established an internal group tasked with developing alternative energy solutions for customers and is continually evaluating new technologies and new opportunities with existing technologies. The Company is cognizant of solar energy technologies and continues to evaluate different solar options. Plan B: Fuel Diversity Plan includes 294 MW (nameplate) of solar, as listed in Figure 1.4.2. The Company has identified three onshore wind projects that have the potential to generate a total of 247 MW (nameplate) with no direct fuel costs. The significant potential for offshore wind adjacent to the Company's service territory is a major focus of this group's current efforts. These are described in more detail in Section 5.4. The Company has included 50 MW (nameplate) solar to be provided by one or more NUGs in Plan A: Base Plan and Plan B: Fuel Diversity Plan. In addition, the Offshore Wind Demonstration Project, onshore wind and generic solar are included as part of Plan B: Fuel Diversity Plan.

While the Planning Period is a 15-year outlook, the Company is mindful of the scheduled license expirations of the Company-owned nuclear units: Surry Unit 1 (838 MW) and Surry Unit 2 (838 MW) in 2032 and 2033, respectively, and North Anna Unit 1 (838 MW) and North Anna Unit 2 (835 MW) in 2038 and 2040, respectively. While this may seem to be in the distant future, the expirations begin to occur within the Study Period, and the scale of these near emissions-free baseload retirements, the potential impact on fuel diversity, and the long lead time associated with developing replacement nuclear generation demand attention when performing long-term planning. Therefore, the Company remains committed to pursuing the development of resources that meet the needs of customers, while supporting the fuel diversity needed to minimize risks associated with changing market conditions, industry regulations, and societal megatrends. As described in Chapter 6, Plan B: Fuel Diversity Plan, under current planning assumptions, costs more than Plan A: Base Plan, which relies almost exclusively on new natural gas-fired generation over the Study Period. While natural gas is a critical component of the Company's fuel mix, nuclear, coal, DSM, and renewable generation are also central components to achieve the Company's objective of long-term fuel diversity, and thus providing price stability and system reliability in an environmentally-responsible manner. Therefore it is prudent for the Company to pursue a path forward that follows an expansion consistent with Plan A: Base Plan, while concurrently continuing forward with reasonable development efforts of the additional resources identified in Plan B: Fuel Diversity Plan. Collectively, this recommended path forward is the 2013 Plan.

Figure 1.4.5(a) and (b) displays the differences between the 2012 Base Plan and the 2013 Base Plan and the 2012 Fuel Diversity Plan (i.e., 2012 Preferred Plan) and the 2013 Fuel Diversity Plan.

Figure 1.4.5(a) CHANGES BETWEEN THE 2012 AND 2013 BASE PLANS

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2012						Approved & Extended DSM Proposed & Future DSM
2013	VCHEC	SPP		AV, HW, SH – Biomass		
2014		~~MSW~~ / SPP		BR3 – Gas BR4 – Gas		
2015	Warren	SPP / **EEP** / **SLR NUG** / **EP&S**	PP5 – SNCR		CEC 1-4 YT1, YT2	
2016	Brunswick					
2017						
2018			YT3 – SNCR			
2019	CC					
2020						
2021	**CT**					
2022	~~CC~~/**CT**					
2023	CT					
2024	~~CT~~					
2025						
2026						
2027	**CC**					
2028						

Key: *Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or natural gas; Retire: Remove a unit from service; AV: Altavista; BR: Bremo; Brunswick: Brunswick County Power Station; CEC: Chesapeake Energy Center Unit; CC: Combined-Cycle; CT: Combustion Turbine (2 units); EEP: Energy Extraction Partners; EP&S: Economic Power & Steam Generation, LLC; HW: Hopewell; MSW: Municipal Solid Waste; PP5: Possum Point Unit 5; SH: Southampton; SNCR: Selective Non-Catalytic Reduction; SLR NUG: Solar NUG; SPP: Solar Partnership Program; VCHEC: Virginia City Hybrid Energy Center; YT: Yorktown Unit.*

Color Key: *Blue: Updated resource since 2012 Plan; Red with Strike: 2012 Plan Resource Placement; Black Circle with Arrow: Resource year movement from 2012 Plan to 2013 Plan.*

Note: 1) *DSM capacity savings continue to increase throughout the Planning Period.*

Figure 1.4.5(b) CHANGES BETWEEN THE 2012 AND 2013 FUEL DIVERSITY PLANS

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2012						Approved & Extended DSM Proposed & Future DSM
2013	VCHEC	SPP		AV, HW, SH – Biomass		
2014		~~MSW~~ / SPP		BR3 – Gas BR4 – Gas		
2015	Warren	SPP / **EEP / SLR NUG / EP&S**	PP5 – SNCR		CEC 1-4 YT1, YT2	
2016	Brunswick					
2017		**SLR TAG / SLR**				
2018		**OFFD / SLR**	YT3 – SNCR			
2019	CC	**SLR**				
2020		SLR TAG / **SLR**				
2021	~~CT~~	**SLR**				
2022	CT	WND				
2023		WND				
2024	North Anna 3	WND				
2025						
2026						
2027	CT					
2028	CT					

Key: *Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or natural gas; Retire: Remove a unit from service; AV: Altavista; BR: Bremo; Brunswick: Brunswick County Power Station; CEC: Chesapeake Energy Center Unit; CC: Combined-Cycle; CT: Combustion Turbine (2 units); EEP: Energy Extraction Partners; EP&S: Economic Power & Steam Generation, LLC; HW: Hopewell; MSW: Municipal Solid Waste; North Anna 3: North Anna Unit 3; OFFD: Offshore Wind Demonstration Project; PP5: Possum Point Unit 5; SH: Southampton; SNCR: Selective Non-Catalytic Reduction; SLR: Generic Solar; SLR NUG: Solar NUG; SLR TAG: Solar Tag; SPP: Solar Partnership Program; Warren: Warren County Power Station; WND: Onshore Wind; YT: Yorktown Unit.*

Color Key: *Blue: Updated resource since 2012 Plan; Red with Strike: 2012 Plan Resource Placement; Black Circle with Arrow: Resource year movement from 2012 Plan to 2013 Plan.*

Note: 1) *DSM capacity savings continue to increase throughout the Planning Period.*

Chapter 2 | Load Forecast

CHAPTER 2 – LOAD FORECAST

2.1 FORECAST METHODS

The Company uses two econometric models with an end-use orientation to forecast energy sales at the customer class level ("sales model") and hourly loads at the system level ("system model"). The models used to produce the Company's load forecast have been developed, enhanced and re-estimated annually for over 20 years. There is no change in forecasting methods used in this 2013 Plan.

The sales model incorporates separate monthly sales equations for residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers, as well as other Load Serving Entities ("LSEs") in the Dominion Zone ("DOM Zone"), all of which are in the PJM RTO. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load.

Variables included in the monthly sales equations are as follows:

a) *Residential Sales equation*: Income, electric prices, unemployment rate, number of customers, appliance saturations, building permits, weather, billing days, and calendar month variables to capture seasonal impacts.
b) *Commercial Sales equation*: Virginia Gross State Product ("GSP"), electric prices, natural gas prices, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
c) *Industrial Sales equation*: Employment in manufacturing, electric prices, weather, billing days, and calendar month variables to capture seasonal impacts.
d) *Public Authorities Sales equation*: Real output (the constant dollar value of all goods and services provided by state and local government), number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
e) *Street and Traffic Lighting Sales equation*: Number of residential customers and calendar month variables to capture seasonal impacts.
f) *Wholesale Customers and Other LSEs Sales equations*: A measure of non-weather sensitive load derived from the residential equation, heating and air-conditioning appliance stocks, number of days in the month, weather, and calendar month variables to capture seasonal and other effects.

The system model utilizes hourly DOM Zone load data and is estimated as a function of time trend variables and a detailed specification of weather. Weather variables used in the system model include both current and lagged values of transformed temperature, humidity, wind speed and sky cover for five weather stations. The model also incorporates estimates of non-weather sensitive load derived from the sales model and residential heating and cooling appliance stocks as explanatory variables. The hourly model also uses calendar month variables to capture time of day, day of week, holiday, other seasonal effects and unusual events such as hurricanes. Separate equations are estimated for each hour of the day.

Hourly models for wholesale customers and other LSEs within the DOM Zone are also modeled as a function of the DOM Zone load since they face similar weather and economic activity. The DOM LSE load is derived by subtracting the other LSEs from the DOM Zone load. DOM LSE load and firm contractual obligations are used as the total load obligation for the purpose of this 2013 Plan.

Forecasts are produced by simulating the model over actual weather data from the past 20 years along with projected economic conditions. Sales estimates from the sales model and energy output estimates from the system model are compared and reconciled appropriately in the development of the final sales, energy, and peak demand forecast that is utilized in the 2013 Plan.

2.2 HISTORY & FORECAST BY CUSTOMER CLASS & ASSUMPTIONS

The Company is typically a summer peaking system with historical DOM Zone summer peak growth averaging about 1.8% annually over 1998-2012. The annual average energy growth rate over the same period is approximately 1.5%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figure 2.2.1 and Figure 2.2.2. DOM LSE peak and energy requirements are estimated to grow at approximately 1.6% and 1.7% annually throughout the Planning Period. Additionally, a 10-year history and 15-year forecast of sales and customer count at the system level, as well as a breakdown of Virginia and North Carolina are provided in Appendices 2A to 2F. Appendix 2G provides a summary of the summer and winter peaks used in the development of the 2013 Plan. Finally, the three-year historical load and 15-year projected load for wholesale customers are provided in Appendix 3L.

Figure 2.2.1 DOM ZONE PEAK LOAD

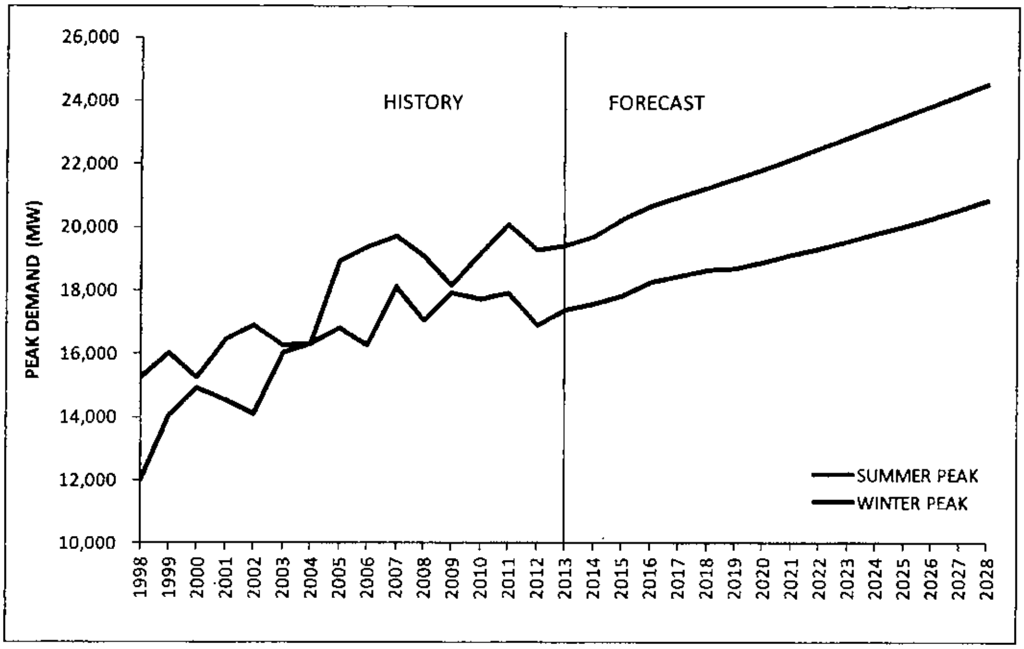


Figure 2.2.2 DOM ZONE ANNUAL ENERGY

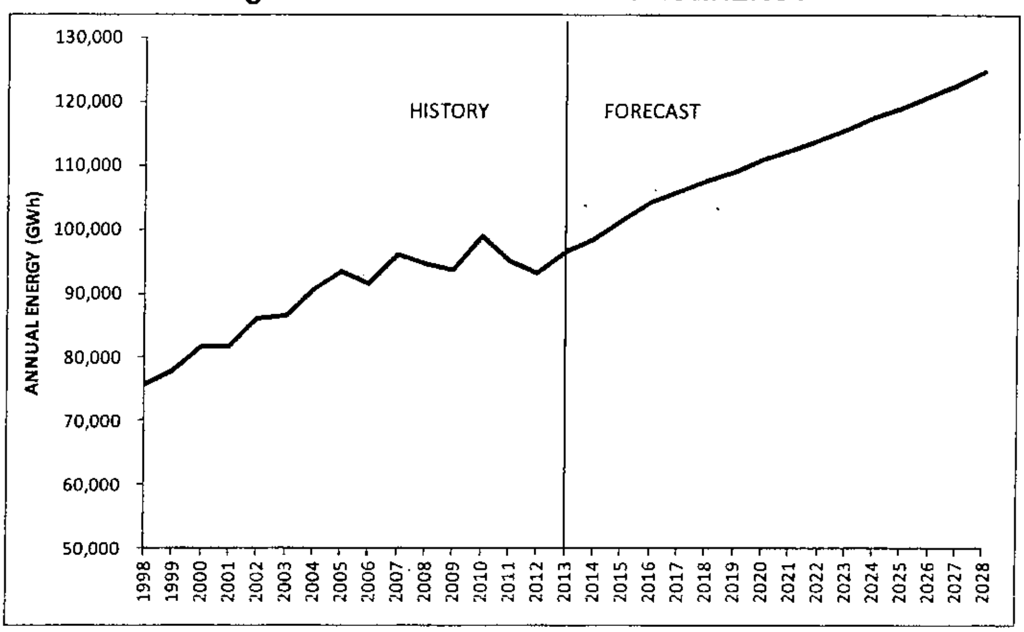


Figure 2.2.3 summarizes the final forecast of energy sales and peak load over the next 15 years. The Company's wholesale and retail customer energy sales are estimated to grow at annual rates of approximately 1.6% and 1.7%, respectively, over the Planning Period as shown in Figure 2.2.3. The difference in these growth rates primarily reflects the growth of the commercial class as a result of data center additions. Historical and projected growth rates can diverge for a number of reasons, including weather and economic conditions.

Figure 2.2.3 SUMMARY OF ENERGY SALES & PEAK LOAD FORECAST

	2014	2028	Compound Annual Growth Rate (%) 2014-2028
DOMINION LSE			
TOTAL ENERGY SALES (GWh)	84,198	106,014	1.7%
Retail	82,185	103,491	1.7%
Residential	30,859	36,129	1.1%
Commercial	32,393	48,597	2.9%
Industrial	8,317	7,838	-0.4%
Public Authorities	10,313	10,567	0.2%
Street and Traffic Lighting	304	360	1.2%
Wholesale (Resale)	2,013	2,523	1.6%
SEASONAL PEAK (MW)			
Summer	17,244	21,439	1.6%
Winter	15,423	18,258	1.2%
ENERGY OUTPUT (GWh)	87,252	109,859	1.7%
DOMINION ZONE			
SEASONAL PEAK (MW)			
Summer	19,677	24,541	1.6%
Winter	17,566	20,853	1.2%
ENERGY OUTPUT (GWh)	98,394	124,599	1.7%

Note: *All sales and peak load have not been reduced for the impact of DSM.*

Figures 2.2.4 and 2.2.5 provide a comparison of DOM Zone summer peak load and energy forecasts included in the 2012 Plan, 2013 Plan, and PJM's load forecast for the DOM Zone from its 2012 and 2013 Load Forecast Reports.[2]

[2] *See* www.pjm.com/documents/~/media/documents/reports/2012-pjm-load-report.ashx; *see also* www.pjm.com/~/media/documents/reports/2013-load-forecast-report.ashx.

Figure 2.2.4 DOM ZONE PEAK LOAD COMPARISON

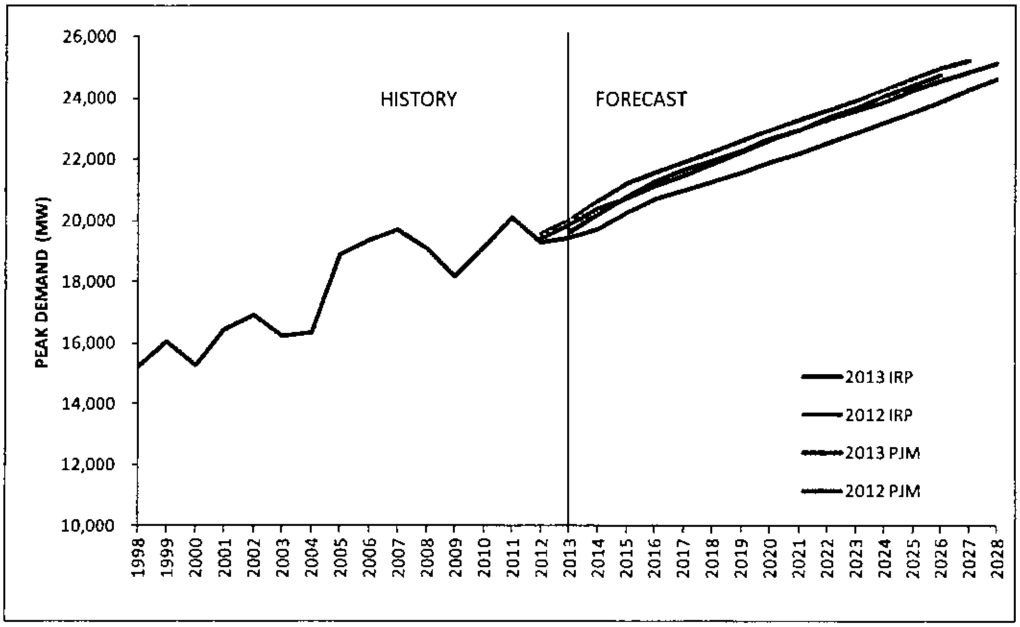
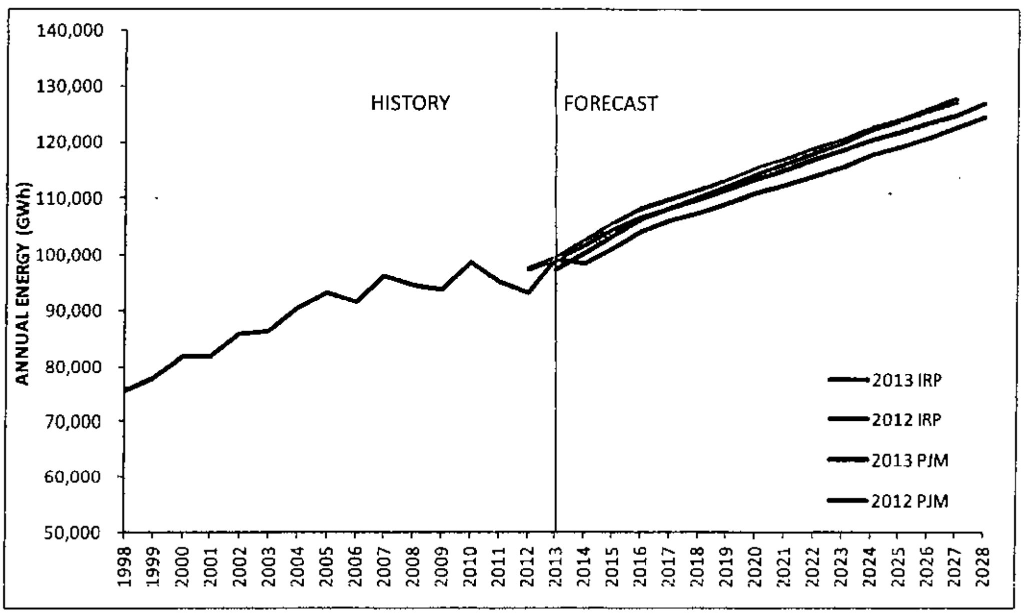


Figure 2.2.5 DOM ZONE ANNUAL ENERGY COMPARISON



The economic and demographic assumptions that were used in the Company's load forecasting models were supplied by Moody's Economy.com prepared in April 2013 and are included as Confidential Appendix 2J. Figure 2.2.6 summarizes the economic variables used to develop the sales and peak load forecasts used in the 2013 Plan.

Figure 2.2.6 MAJOR ASSUMPTIONS FOR THE ENERGY SALES & PEAK DEMAND MODEL

	2014	2028	Compound Annual Growth Rate (%) 2014 - 2028
DEMOGRPAHIC:			
Customers (000)			
Residential	2,237	2,638	1.2%
Commercial	239	277	1.0%
Population (000)	8,357	9,521	0.9%
ECONOMIC:			
Employment (000)			
State & Local Government	551	586	0.4%
Manufacturing	233	221	-0.4%
Government	723	755	0.3%
Income ($)			
Per Capita Real disposable	35,622	44,575	1.6%
Price Index			
Consumer Price (1982-84=100)	239	321	2.1%
VA Gross State Product (GSP)	406	569	2.4%

The forecast for the Virginia economy is a key driver in the Company's energy sales and load forecasts. Although Virginia has been impacted by the recent recession, the Commonwealth fared well compared to the nation in terms of job losses. As of April 2013, the seasonally adjusted unemployment rate in Virginia approached 5.2%, approximately 2.4% below the national unemployment rate. Virginia's unemployment rate ranks among the lowest in the nation and is expected to continue to improve over the next few years.

Housing starts and associated new homes are a significant contributor to electric sales growth in the Company's service territory. The sector saw significant year-over-year declines in the construction of new homes from 2006 through 2011 and began showing improvements in 2012. As such, Virginia is expected to show significant improvement in housing starts in 2013 through 2020 which is reflected as new customers in the load forecast. Near-term housings starts are forecast to expand quickly and then revert back to the long-run average after 2020, when supply and demand become balanced.

Another driver of energy sales and load forecasts in the Company's service territory is new and existing data centers. The Company has seen significant interest in data centers locating in Virginia because of its proximity to fiber optic networks as well as low-cost, reliable power sources. The Company expects new and existing data center demand to increase to nearly 900 MW by 2015, which equates to growth of roughly 65% relative to 2013 levels.

Additionally, Virginia investments in transportation infrastructure are expected to enhance continued economic expansion. For example, the Commonwealth of Virginia recently announced a plan to build a new $1.4 billion 55 mile section of US Route 460 in southeastern Virginia. This project, according to Chmura Economics, is expected to generate 4,000 jobs during construction and approximately 14,000 jobs over the long-term from new business opportunities such as tourism and freight traffic at the Port of Virginia.

On a long-term basis, the economic outlook for Virginia is positive. Over the next 15 years, real per-capita income in the state is expected to grow about 1.6% per year on average, while real GSP is projected to grow more than 2.4% per year on average. During the same period, the Virginia population is expected to grow steadily at an average rate of approximately 0.94% per year.

2.3 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

The three-year actual and 15-year forecast of summer and winter peak, annual energy, DSM peak and energy, and system capacity are shown in Appendix 2H. Additionally, Appendix 2I provides the reserve margins for a three-year actual and 15-year forecast.

2.4 ECONOMIC DEVELOPMENT RATES

As of August 1, 2013, the Company has four customers in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 19 MW as of August 1, 2013. There are no customers under a self-generation deferral rate.

On March 30, 2012, the Company filed an application with the NCUC requesting authority to adjust and increase its rates for retail electric service in North Carolina. The application included a proposal for a special Economic Development Rate, Rider EDR. On December 21, 2012, the NCUC issued its Order Granting General Rate Increase (NCUC Docket No. E-22, Sub 479) finding, among other things, that Rider EDR should be approved subject to the condition that the discount shall be adjusted should the revenues produced by the Rider not cover the marginal costs of providing service.

Chapter 3

Existing & Proposed Resources

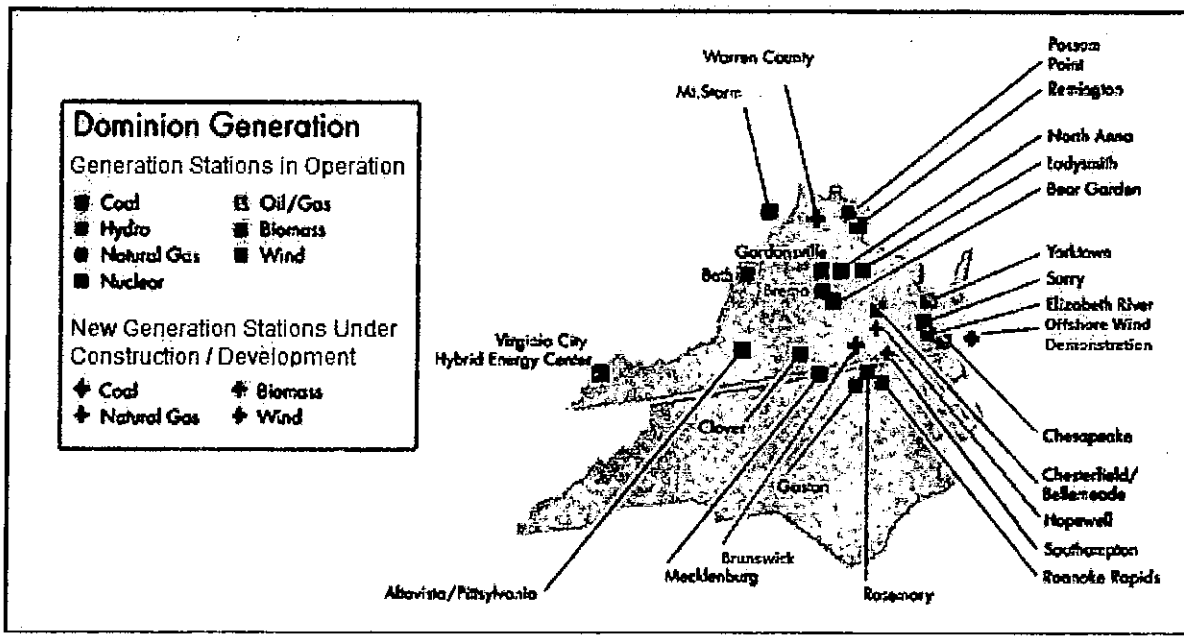
CHAPTER 3 – EXISTING & PROPOSED RESOURCES

3.1 SUPPLY-SIDE RESOURCES

3.1.1 EXISTING GENERATION

The Company's existing generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 3.1.1.1. This diverse fleet of 101 generation units includes 4 nuclear, 20 coal, 2 natural gas-steam, 8 combined-cycles, 41 combustion turbines, 4 biomass, 2 heavy oil, 6 pumped storage, and 14 hydro units with a total summer capacity of approximately 17,705 MW.[3] The Company's continuing operational goal is to manage this fleet in a manner that provides reliable, cost-effective service under varying load conditions.

Figure 3.1.1.1 EXISTING GENERATION RESOURCES



The Company owns a variety of generation resources that operate using a diverse set of fuels. The largest proportion of the Company's generation resources has operated for 40 to 50 years, followed by a large number of units that have operated for 20 to 30 years and 30 to 40 years. Figure 3.1.1.2 shows the demographics of the entire existing generation fleet.

[3] All references to MW in Chapter 3 refer to summer capacity unless otherwise noted. Winter capacities for Company-owned generation units are listed in Appendix 3A.

Figure 3.1.1.2 GENERATION FLEET DEMOGRAPHICS

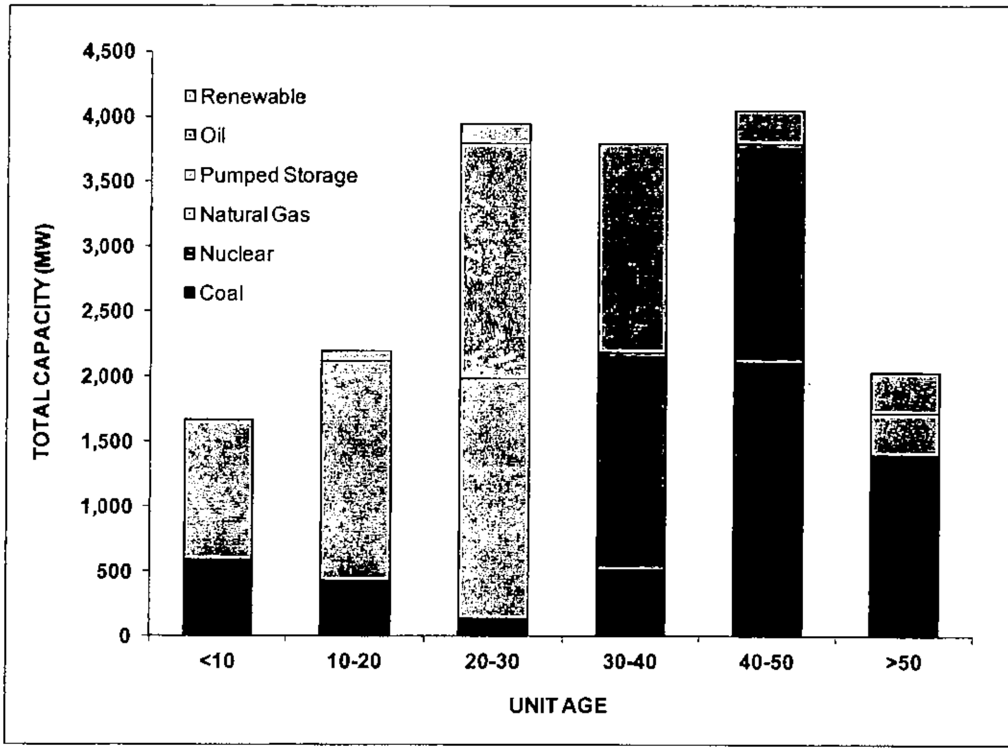


Figure 3.1.1.3 illustrates that the Company's existing generation fleet is comprised of a mix of approximately 17,705 MW of resources with varying operating characteristics and fueling requirements. The Company also has contracted 1,747 MW of NUGs, which provide firm capacity as well as associated energy and ancillaries to meet the Company's load requirements. An important aspect of the 2013 Plan is the Company's use of diverse capacity and energy resources to meet its customers' needs.

Figure 3.1.1.3 2013 CAPACITY RESOURCE MIX BY UNIT TYPE

Generation Resource Type	Net Summer Capacity	Percentage (%)
Coal	5,206	26.1%
Nuclear	3,349	16.8%
Natural Gas	4,927	24.7%
Pumped Storage	1,802	9.0%
Oil	1,861	9.3%
Renewable	561	2.8%
NUG - Coal	743	3.7%
NUG - Natural Gas Turbine	942	4.7%
NUG - Renewable	63	0.3%
Purchases	510	2.6%
NUG Contracted	1,747	8.8%
Company Owned	17,705	88.7%
Company Owned and NUG Contracted	19,453	97.4%
Total	19,962	100.0%

Due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is economically dispatched by PJM within its larger footprint, ensuring that customers in the Company's service area receive the benefit from all resources in the PJM power pool regardless of whether the source of electricity is Company-owned, contracted, or third-party units. PJM dispatches resources within the DOM Zone from the lowest bid units to the highest bid units, while maintaining its mandated reliability standards. Figures 3.1.1.4 and 3.1.1.5 provide the Company's 2012 actual capacity and energy mix with percentages.

Figure 3.1.1.4 2012 ACTUAL CAPACITY MIX

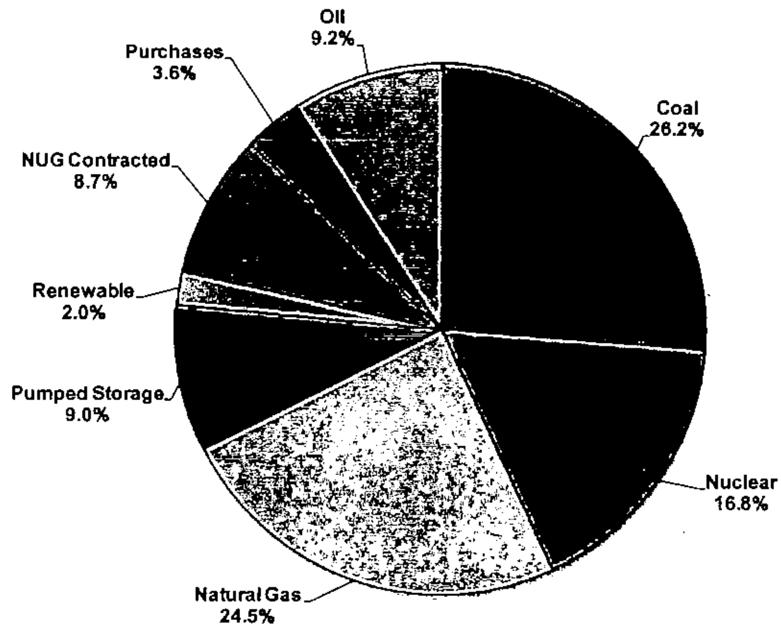
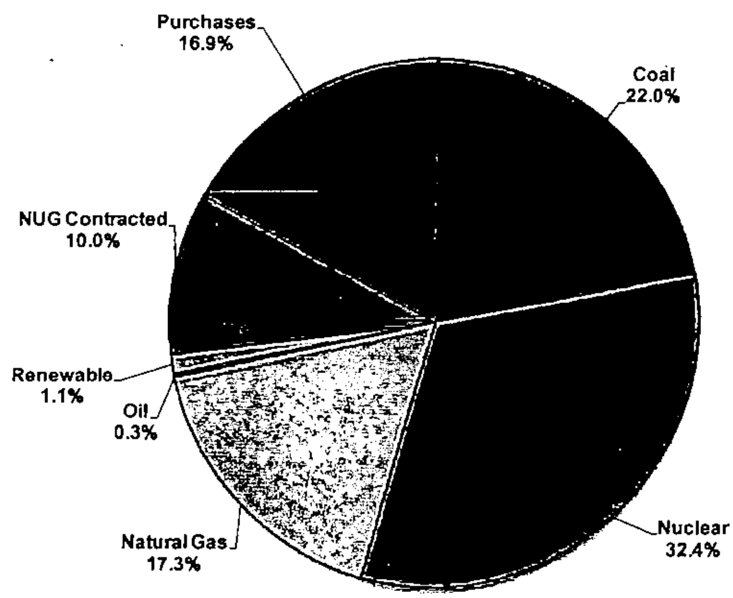


Figure 3.1.1.5 2012 ACTUAL ENERGY MIX[1]



Note 1): *Pumped storage is not shown because it is net negative to the Company's energy mix.*

Appendices 3A, 3C, 3D, and Extraordinarily Sensitive 3E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Additionally, Appendix 3F provides a summary of the existing capacity, including NUGs, by fuel class. Appendices 3G and 3H provide energy generation by type as well as the system output mix. Appendix 3B provides a listing of other generation units including units in cold storage, NUGs, behind-the-meter generation ("BTMG"), and customer-owned generation units.

3.1.2 EXISTING RENEWABLE RESOURCES

The Company currently owns and operates 561 MW of renewable resources including its wood-burning Pittsylvania Power Station (83 MW), one of the largest biomass facilities in the United States. The Company also owns and operates four hydro facilities: Gaston Hydro Station (220 MW), Roanoke Rapids Hydro Station (95 MW), Cushaw Hydro Station (2 MW), and North Anna Hydro Station (1 MW). The Company completed the conversion of Altavista (51 MW) on July 12, 2013, and will also complete the conversion of its Hopewell (51 MW) and Southampton (51 MW) units from coal to biomass fuel in 2013. Also, in 2013, the Company will complete the installation of 1 MW (6 MW nameplate) of the Solar Partnership Program. Further, VCHEC (600 MW) is expected to consume renewable biomass fuel of up to 1% (6 MW) by the end of its first year of operation and gradually increase that level to 10% (60 MW) by 2020.

The 2013 Plan continues to include a renewable municipal solid waste NUG facility at Covanta Fairfax that will provide approximately 63 MW of firm capacity in 2013, as well as existing contracts for approximately 25 MW of BTMG renewable capacity.

3.1.3 CHANGES TO EXISTING GENERATION

The Company is fully committed to meeting its customers' energy needs in a manner consistent with a clean environment and supports the establishment of a comprehensive national energy and environmental policy that balances the country's needs for reliable and affordable energy with a reasonable minimization of environmental impacts. The Company has a mixed portfolio of generating units, including carbon-free nuclear and hydro and has lower carbon intensity compared to most other energy companies in the country.

The Company filed for a Certificate of Public Convenience and Necessity ("CPCN") with the SCC to repower its coal-fired Bremo Power Station with natural gas on August 31, 2012. The Bremo Power Station currently has two units, Unit 3 and Unit 4, which have been in service since 1950 and 1958, respectively. Unit 3 has a summer capacity of 71 MW and Unit 4 has a summer capacity of 156 MW. This conversion is expected to reduce the Company's emissions of SO_2, NO_x, particulate matter, Carbon Dioxide ("CO_2"), and Hg. The conversion is expected to be complete in 2014.

<u>Uprates and Derates</u>

Efficiency, generation output, and environmental characteristics of plants are reviewed as part of the Company's normal course of business. Many of the uprates and derates discussed in this section occur during routine maintenance cycles or are associated with standard refurbishment. However, several plant ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations.

The Company continues to evaluate opportunities for existing unit uprates as a cost-effective means of increasing generating capacity and improving system reliability. Since 2010, the Company's investment in its existing generation fleet has yielded net capacity uprates of 218 MW. Appendix 3I provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

<u>EPA Regulations</u>

There are a significant number of effective and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. As shown in Figure 3.1.3.1, these regulations are designed to regulate air, solid waste, and water constituents.

Figure 3.1.3.1 EPA REGULATIONS AS OF AUGUST 30, 2013

Constituent		Key Regulation	Final Rule
AIR	Hg/HAPS	Mercury & Air Toxics Standards (MATS)	2011
	SO_2	2010 CAIR	2005
		2015 CAIR	2005
		SO_2 NAAQS	2010
	NOx	Ozone Std Rev (75 ppb)	2008
		Ozone Standard Rev (60-70 ppb)	2014
		2009 CAIR	2005
		2015 CAIR	2005
	CO_2	GHG Tailoring Rule	2010
		EGU NSPS (New)	2014
		Federal CO_2 Program &/or EGU NSPS (Existing)/CAP	June 2015
WASTE	Ash	CCB's	Late 2013
WATER	Water 316(b)	316(b) Impingement	2013
		316(b) Entrainment	
	Water Effluent	Effluent Discharges	2014

***Key: Constituent**: Hg: Mercury; HAPS: Hazardous Air Pollutants; SO_2: Sulfur Dioxide; NO_x: Nitrogen Oxide; CO_2: Carbon Dioxide; GHG: Greenhouse Gas; Water 316b: Clean Water Act § 316(b) Cooling Water Intake Structures;*

***Regulation**: MATS: Mercury & Air Toxics Standards; CAIR: Clean Air Interstate Rule; CAP: President's Climate Action Plan; SO_2 NAAQS: Sulfur Dioxide National Ambient Air Quality Standards; Ozone Std Rev PPB: Parts Per Billion; EGU NSPS: Electric Generating Units New Source Performance Standard; CCB: Coal Combustion Byproducts.*

Compliance with effective and anticipated environmental regulations is an important part of the Company's planning process and a key corporate focus. The majority of the Company's coal generators are equipped with scrubbers and NO_x controls; however, the remaining small coal-fired units are without sufficient emission compliance controls to comply with soon to be effective and anticipated regulatory requirements. The Company's coal-fired units at the Chesterfield, Mt. Storm, Clover, Mecklenburg and VCHEC facilities have flue gas desulfurization environmental controls to control SO_2 emissions. The Company's Chesterfield Units 4, 5 and 6, Mt. Storm, Clover, Chesapeake Units 3 and 4, and VCHEC coal-fired generation units also have selective catalytic reduction ("SCR") or SNCR technology to control NO_x emissions.

As part of its IRP process, the Company monitors options with respect to the Company's coal and oil-fired units that would not be compliant without additional potentially uneconomic capital investments with soon to be effective and anticipated environmental regulations as currently detailed and understood. In 2012, the Company reviewed and analyzed the costs to retrofit units with new environmental control equipment, repower units to natural gas, convert units to burn biomass as a fuel source, or retire the units from service. This analysis sought to determine the optimal option, while considering costs and the goal of maintaining system reliability.

After this analysis was completed during the 2012 IRP process, EPA regulations that impact the Company's generation fleet have changed very little.

As a result, the Company's 2013 Plan remains largely unchanged compared to its 2012 Plan regarding retrofitting, repowering, and retiring units affected by EPA regulations. However, the expected installation of the SNCR controls on Yorktown 3 and Possum Point 5, which has been delayed, will both be online in 2018.

3.1.4 GENERATION RETIREMENTS/BLACKSTART

Retirements

Based on the effective and anticipated environmental regulations along with current market conditions and consistent with the 2012 Plan, the 2013 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. There are several units in the 2013 Plan that will be retired by 2015. These units include the Chesapeake Energy Center Units 1 (111 MW), 2 (111 MW), 3 (156 MW), and 4 (217 MW) and Yorktown Units 1 (159 MW) and 2 (164 MW). Appendix 3J lists the planned retirements included in the 2013 Plan.

Blackstart

The Company is also evaluating future blackstart resources based on asset retirements that are anticipated over the next several years. Blackstart generators are generating units that are able to start without an outside electrical supply or are able to remain operating at reduced levels when automatically disconnected from the grid. The North American Electric Reliability Corporation ("NERC") Reliability Standard EOP-005 requires the RTO to have a plan that allows for restoring its system following a complete shutdown (i.e., blackout). As the RTO, PJM performs an analysis to verify all requirements are met and coordinates this analysis with the Company in its role as the Transmission Owner. Currently, the Company and other PJM members are working with PJM to implement a newly developed, long-term, RTO-wide strategy for procuring blackstart resources. This strategy will ensure a resilient and robust ability to meet blackstart and restoration requirements. It is described in detail in Section 10 of PJM Manual 14D – Generator Operational Requirements. PJM will issue an RTO-wide Request for Proposals ("RFP") for blackstart generation every five (5) years, which will be open to all existing and potential new blackstart units on a voluntary basis. Resources will be selected based upon the individual needs of each transmission zone. The first five year selection process will result in blackstart solutions that will be effective as of April 1, 2015. Blackstart solutions from subsequent five-year selection processes will be effective on April 1, beginning in 2020 and continuing every five years thereafter. For incremental changes in resource needs or availability that may arise between the five-year solicitations, the strategy includes an incremental RFP process.

This new strategy supersedes the Company's previous strategy of using the now obsolete PJM Blackstart Replacement Process to request a total of approximately 250 MW of necessary additional blackstart generation in increments of at least 50 MW per year for five years between 2013 and the end of 2018. The Replacement Process was used in 2012 to successfully acquire approximately 50 MW of blackstart service at the Company's Gordonsville Power Station. The new strategy will produce similar results and will ensure a resilient and robust ability to meet blackstart and restoration requirements. For more information, please see the blackstart service section of PJM's website.[4]

3.1.5 GENERATION UNDER CONSTRUCTION

To meet expected load growth, the Company filed for a CPCN with the SCC to construct and operate Warren County Power Station, a 1,337 MW natural gas-powered electric generation facility located in Warren County, Virginia. On February 2, 2012, the SCC granted the CPCN in Case No. PUE-2011-00042, and on February 27, 2012, the Company officially began construction of the station. The station will generate enough electricity for more than 300,000 homes at peak demand, which is critical to the Company's strategy to meet the growing need for electricity. The station is targeted for commercial operation by 2015.

Additionally, pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly (House Bill 1686) the Company obtained a CPCN from the SCC in November 2012 (Case No. PUE-2011-00117) for the Solar Partnership Program to install up to 30 MW of solar PV distributed generation ("DG") by 2015 in its Virginia service territory. Installations will be placed on existing structures (e.g., customers' rooftops) and previously developed properties (e.g., ground-mounted solar arrays) to assess the potential impacts and benefits on its distribution system. On May 2, 2013,

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[4] *See* http://www.pjm.com/markets-and-operations/ancillary-services/black-start-service.aspx.

the Company announced that Old Dominion University ("ODU") was the first participant in the Solar Partnership Program. More than 600 solar panels, with a grid capacity of 132 kW, will be installed during the summer of 2013 on the roof of ODU's Student Recreation Center.

On November 2, 2012, the Company filed an application for a CPCN with the SCC to construct and operate Brunswick County Power Station, a 1,375 MW natural gas powered electric generation facility located in Brunswick County, Virginia, and associated facilities. On August 2, 2013, the SCC issued an order granting the CPCN, in Case No. PUE-2012-00128.

Figure 3.1.5.1 and Appendix 3K provide a summary of the generation under construction along with the forecasted in-service date and summer/winter capacity.

Figure 3.1.5.1 GENERATION UNDER CONSTRUCTION

Forecasted COD[1]	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW)	
					Summer	Winter
2015	Warren County Power Station	Warren County, VA	Natural Gas	Intermediate/ Baseload	1,337	1,437
2015	Solar Partnership Program	VA	Solar	Intermitent	24[2]	24[2]
2016	Brunswick County Power Station	Brunswick, VA	Natural Gas	Intermediate/ Baseload	1,375	1,509

Notes:
1) Commercial Operation Date.
2) Solar Partnership Program DC capacity is 30 MW (nameplate) while the figure displays alternating current ("AC") capacity.

3.1.6 NON-UTILITY GENERATION

A portion of the Company's load and energy requirements is supplemented with contracted NUG units and market purchases. The Company has existing contracts with NUGs for capacity of 1,747 MW from nine units, of which 63 MW are from renewable sources. These nine NUGs are considered firm capacity resources and are included in the 2013 Plan. BTMGs that the Company does not have a contract to purchase capacity from on a firm basis are not included in this Plan as a firm capacity resource.

Each of the NUG facilities listed as a capacity resource in Appendix 3B is under contract to supply capacity and energy to the Company. NUG units are obligated to provide firm capacity and energy at the contracted terms during the life of the contract. The firm capacity from NUGs is included as a resource in meeting the reserve requirements. In 2011, the Company was notified by three of its NUGs that those resources (totaling 316 MW) would be unavailable as direct resources to the Company after the expiration of the existing contracts. The remaining NUG contracts expire at different times during the Planning Period, with the last contract expiring in 2021.

The 2013 Plan also includes capacity and energy from a renewable NUG, EEP, which is expected to be online by 2015. EEP was generically identified in the 2012 Plan as "MSW," standing for Municipal Solid Waste. The Company has also recently executed a PPA with EP&S for a 20 MW biomass/wood facility located in Lewiston, NC. This project is a qualifying facility under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and is expected to be online in 2015. Additionally, the Company is currently evaluating a number of potential solar NUG facilities. While no PPAs have been signed as of the date of this filing, the base plan selected a total of 50 MW (nameplate) of solar, with one or more NUGs beginning in 2015, based on preliminary evaluations of several opportunities. The Company is continually evaluating NUG opportunities as they arise to determine if they are in the best interest of customers.

For modeling purposes, the Company assumed that its NUG capacity will be available as a firm resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned/sponsored supply- or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

3.1.7 WHOLESALE & PURCHASED POWER

Purchased Power

Except for the NUG contracts discussed in Section 3.1.6, the Company does not have any bilateral contractual obligations with wholesale power suppliers or power marketers. As a member of PJM, the Company has the option to self-schedule or buy capacity through the Reliability Pricing Model ("RPM") auction process. The Company has procured its capacity obligation from the RPM market through May 31, 2017. In Plan A: Base Plan, the Company annually makes net purchases on average of 127 MW of capacity and 12% of its total energy over the Planning Period from the PJM market. In Plan B: Fuel Diversity Plan, the Company annually makes net purchases on average of 173 MW of capacity and 12% of its total energy over the Planning Period from the PJM market.

Wholesale Power Sales

The Company currently provides full requirements wholesale power sales to three entities, which are included in the Company's load forecast. These entities are Craig Botetourt Electric Cooperative; the Virginia Municipal Electric Association No.1; and the Town of Windsor in North Carolina. Additionally, the Company has partial requirements contracts to supply the supplemental power needs of the North Carolina Electric Membership Cooperative. Appendix 3L provides a listing of wholesale power sales contracts with parties whom the Company has either committed to, or expects to sell power during the Planning Period.

Behind-the-Meter Generation

BTMG occurs on the customer's side of the meter. The Company purchases all output from the customer and services all of the customer's capacity and energy requirements. Since the Company does not own or control these resources, they were not used to develop the 2013 Plan. The unit descriptions are provided in Appendix 3B.

3.1.8 REQUEST FOR PROPOSAL

At this time, the Company does not have any RFPs outstanding to procure supply-side resources.

3.2 DEMAND-SIDE RESOURCES

The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. Demand-side resources encourage the more efficient use of existing resources and delay or eliminate the need for new supply-side infrastructure. The Company's DSM tariffs provide customers with price signals to curtail load at times when system load or marginal cost is high. Additionally, the Company's DSM programs are designed as a way to provide customers the opportunity to manage their electricity usage. In the 2013 Plan, five categories of DSM programs are addressed: i) those approved and extended by the SCC and NCUC; ii) those proposed by the Company in Case No. PUE-2013-00072, for which the Company is requesting approval of in Virginia; iii) those proposed by the Company in Docket Nos. E-22, Subs 495, 496, 497, 498, 499, 500, for which the Company is requesting approval of in North Carolina; iv) those considered future programs that are not currently filed with either Commission for approval, but are potential DSM resources; and v) those programs currently rejected from further consideration at this time. System-wide DSM programs were designed and evaluated using a system-level analysis. For reference purposes, Figure 3.2.1 provides a graphical representation of the approved, extended, proposed, future, and rejected programs described in Chapters 3 and 5.

Figure 3.2.1 DSM TARIFFS & PROGRAMS

Voltage Conservation Program	Status (VA/NC)
Standby Generator Tariff	Approved / Approved
Curtailable Service Tariff	
Program	**Status (VA/NC)**
Air Conditioner Cycling Program	Approved / Approved
Residential Low Income Program	
Residential Lighting Program	Completed / Completed
Commercial Lighting Program	Closed / Suspended
Commercial HVAC Program	
Non-Residential Distributed Generation Program	Approved / Rejected
Non-Residential Energy Audit Program	Approved / Proposed
Non-Residential Duct & Sealing Program	
Residential Bundle Program	Approved / Proposed
Residential Home Energy Check-Up Program	
Residential Duct & Sealing Program	
Residential Heat Pump Tune Up Program	
Residential Heat Pump Upgrade Program	
Non-Residential Solar Window Film Program	Proposed / Future
Non-Residential Lighting Systems & Controls Program	
Non-Residential Heating & Cooling Efficiency Program	
Voltage Conservation Program	Future / Future
Non-Residential Re-Commissioning Program	
Non-Residential Custom Incentive Program	
New Residential Low Income Program	
Non-Residential HVAC Tune-Up Program	Rejected and Currently Not Under Consideration
Energy Management System Program	
ENERGY STAR® New Homes Program	
Geo-Thermal Heat Pump Program	
Home Energy Comparison Program	
Home Performance with ENERGY STAR® Program	
In-Home Energy Display Program	
Premium Efficiency Motors Program	
Programmable Thermostat Program	
Residential Refrigerator Turn-In Program	
Residential Solar Water Heating Program	
Residential Water Heater Cycling Program	
Residential Comprehensive Energy Audit Program	
Residential Radiant Barrier Program	
Residential Lighting (Phase II) Program	
Non-Residential Refrigeration Program	

Notes:

1. *North Carolina only programs are being proposed to replace the suspended Commercial Lighting and Commercial HVAC Programs. Also new system level commercial lighting and HVAC programs are being proposed in Virginia, and if approved will replace the North Carolina only programs.*
2. *The Company is requesting expedited treatment to add enhanced measures to the Non-Residential Energy Audit Program.*

3.2.1 DSM PROGRAM DEFINITIONS

For purposes of its DSM programs in Virginia, the Company applies the Virginia definitions set forth in Va. Code § 56-576 as provided below.

- Demand Response – Measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

- Energy Efficiency Program – A program that reduces the total amount of electricity that is required for the same process or activity implemented after the expiration of capped rates. Energy efficiency programs include equipment, physical, or program change designed to produce measured and verified reductions in the amount of electricity required to perform the same function and produce the same or a similar outcome. Energy efficiency programs may include, but are not limited to, i) programs that result in improvements in lighting design, heating, ventilation, and air conditioning systems, appliances, building envelopes, and industrial and commercial processes; ii) measures, such as, but not limited to, the installation of advanced meters, implemented or installed by utilities, that reduce fuel use or losses of electricity and otherwise improve internal operating efficiency in generation, transmission, and distribution systems; and (iii) customer engagement programs that result in measurable and verifiable energy savings that lead to efficient use patterns and practices. Energy efficiency programs include demand response, combined heat and power and waste heat recovery, curtailment, or other programs that are designed to reduce electricity consumption, so long as they reduce the total amount of electricity that is required for the same process or activity. Utilities are authorized to install and operate such advanced metering technology and equipment on a customer's premises; however, nothing in Chapter 23 of Title 56 establishes a requirement that an energy efficiency program be implemented on a customer's premises and be connected to a customer's wiring on the customer's side of the inter-connection without the customer's expressed consent.
- Peak-Shaving – Measures aimed solely at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

For purposes of its DSM programs in North Carolina, the Company applies the definitions set forth in NCGS § 62-133.8 (a) (2) and (4) for DSM and energy efficiency measures as defined below.

- Demand-Side Management – Activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to nonpeak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.
- Energy Efficiency Measure – Equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. "Energy efficiency measure" does not include DSM.

3.2.2 CURRENT DSM TARIFFS

The Company modeled existing DSM pricing tariffs over the Study Period, based on historical data from the Company's Customer Information System. These projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future. No active DSM tariffs were discontinued since the Company's 2012 Plan.

STANDBY GENERATION & CURTAILABLE SERVICE TARIFFS

Program Type:	Energy Efficiency - Demand Response
Target Class:	Commercial & Industrial
Participants:	8 customers on Standby Generation in Virginia
	1 customer on Curtailable Service in Virginia
Capacity Available:	See Figure 3.2.2.1

The Company currently offers two DSM pricing tariffs including Standby Generation ("SG") rate schedules in Virginia and a Curtailable Service ("CS") rate schedule in Virginia. These tariffs provide incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed.

The SG rate schedules provide a direct means of implementing load reduction during peak periods by transferring load normally served by the Company to a customer's standby generator. The customer receives a bill credit based on a contracted capacity level or average capacity generated during a billing month when SG is requested. The CS rate schedule requires the participating customer to reduce its electric demand to a contracted firm demand level when requested by the Company in return for a rate reduction credit. Failure to comply with the Company's request to reduce demand to the firm level results in a penalty, based on a demand charge that is approximately four times the per kilowatt ("kW") credit, on the customer's bill. To receive the rate credit, customers commit to participate in the curtailment upon at least two hours' notice. The tariff is primarily aimed at customers with the operational flexibility to store inventory or to curtail or reschedule production.

During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator, while the customer receiving service under the CS rate schedule is required to reduce load to a contracted firm demand level. At the Company's request, the customer may be asked to reduce load on the Company's system 19 times during the summer (May 16 – September 30) and 13 times during the winter (December 1 – March 31). Additional jurisdictional rate schedule information is available on the Company's website at www.dom.com.

Figure 3.2.2.1 ESTIMATED LOAD RESPONSE DATA

Tariff	Summer 2012 Number of Events	Summer 2012 Estimated MW Reduction	Winter 2012 Number of Events	Winter 2012 Estimated MW Reduction
Standby Generation	17	4	1	3
Curtailable Service	4	3	4	3

3.2.3 CURRENT & COMPLETED DSM PILOTS & DEMONSTRATIONS

Pilots

On September 18, 2007, the Company filed with the SCC for approval of nine conservation, energy efficiency, education, demand response, and load management Pilots. The SCC issued a Final Order on January 17, 2008, that approved the Pilots finding that they were necessary to gather information to help the Commonwealth determine methods to achieve the legislative goal affirmed by the Virginia Energy Plan of reducing energy demand by 10% (using 2006 as the base year) by 2022, approximately 6,170 gigawatt-hour ("GWh") reduction. The Pilots were designed not only to reduce sales and peak demand, but to also gain valuable operational information and data on customer usage and customer acceptance of DSM programs. The nine approved and extended Pilots included:

1. Direct Load Control – Outdoor Air-Conditioning Control Device Pilot
2. Programmable Thermostats – Indoor Air-Conditioning Control Device Pilot
3. Programmable Thermostats with Advanced Metering Infrastructure and Critical Peak Pricing Pilot
4. Standard Residential In-Home Energy Audits Pilot
5. ENERGY STAR® Qualified Homes Energy Audits Pilot
6. Energy Efficiency Welcome Kits Pilot
7. PowerCost™ Monitor Pilot
8. Small Commercial On-Site Energy Audits Pilot
9. Distributed Generation Pilot Program

In March 2009, the Company filed with the SCC its Final Quarterly Report on the status of the Pilots (Case No. PUE-2007-00089).

Since that SCC filing, the Company has filed four follow-ups or quarterly reports regarding the status of its Pilots. The DG Pilot is the only Pilot from Case No. PUE-2007-00089 that has active participants. On April 6, 2010, the SCC issued an Order granting the Company's motion to continue reporting on its DG Pilot on October 31 of each year instead of quarterly reports. The First Annual Report on the DG Pilot was filed on October 29, 2010, the Second Annual Report on the DG Pilot was filed on October 31, 2011, and the Third Annual Report on the DG Pilot was filed on October 31, 2012. Most of the DG Pilot participants have now been enrolled into the new Non-Residential Distributed Generation Program which was approved in Case No.

PUE-2012-00093. Those customers who remain in the DG Pilot may do so until the end of the Pilot in December 2014.

The Company has received SCC approval for implementation of other pilots than those listed above. Descriptions of the Company's pilot programs that have received SCC approval are provided below:

Dynamic Pricing Tariffs Pilot

State:	Virginia
Target Class:	Residential and Non-Residential
Pilot Type:	Peak-Shaving
Pilot Duration:	Enrollment closed on December 1, 2012 Pilot is currently scheduled to conclude November 30, 2013, but the Company filed a Petition (Case No. PUE-2010-00135) on March 22, 2013 to Extend, Expand, and Modify the Pilot.

Pilot Description:

On September 30, 2010, the Company filed an application with the SCC (Case No. PUE-2010-00135) proposing to offer three experimental and voluntary dynamic pricing tariffs to prepare for a potential system-wide offering in the future. The filing was in response to the SCC's July 30, 2010 Order Establishing Pilot Programs issued in Case No. PUE-2009-00084, which, among other things, directed the Company to establish a pilot program under which eligible customers/renewable generators volunteering to participate would be provided the ability to purchase and sell electricity to the Company at dynamic rates.

A dynamic pricing schedule allows the Company to apply different prices as system production costs change. The basic premise is that if customers are willing to modify behavior and use less electricity during high price periods, they will have the opportunity to save money, and the Company in turn will be able to reduce the amount of energy it would otherwise have to generate or purchase during peak periods.

Specifically, the Company proposed a pilot program of 2,000 participants consisting of up to 1,000 residential customers taking service under experimental dynamic pricing tariff DP-R and 1,000 commercial/general customers taking service under dynamic pricing tariffs DP-1 and DP-2. Participation in the pilot requires either an Advanced Metering Infrastructure ("AMI") meter or an existing Interval Data Recorder ("IDR") meter at the customer location. The meter records energy usage every 30 minutes, which enables the Company to offer pricing that varies based on the time of day. In addition, the pricing varies based on the season, the classification for the day, and the customer's demand. Therefore, the AMI or IDR meter coupled with the dynamic pricing schedules allows customers to manage their energy costs based on the time of day.

Additional information regarding the pilot is available at http://www.dom.com/smartprice.

Current Pilot Status:

The Pilot program was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011. The Company launched this Pilot program on July 1, 2011. As of July 1, 2013, there were 638 customers taking service under the residential DP-R tariff; 34 customers taking service under the commercial DP-1 tariff; and 70 customers taking service under the commercial DP-2 tariff.

The Company filed a Petition to Extend, Expand and Modify the Dynamic Pricing Tariffs Pilot with the SCC (Case No. PUE-2010-00135) on March 22, 2013. The Petition would extend the tariffs beyond the November 30, 2013 expiration date, through and including January 31, 2016. The Petition would also set a new Pilot enrollment limit of 2,000 residential customers. The Petition did not include an increase in the Pilot enrollment limit for commercial/general service customers taking service under Rate Schedule DP-1 and DP-2.

The matter is currently pending before the SCC.

<u>Electric Vehicle ("EV") Pilot</u>

State:	Virginia
Target Class:	Residential
Pilot Type:	Peak-Shaving
Pilot Duration:	Enrollment began October 3, 2011 Enrollment concludes December 1, 2013 Pilot concludes November 30, 2014

Pilot Description:

On January 31, 2011, the Company filed an application with the SCC (Case No. PUE-2011-00014) proposing a pilot program to offer experimental and voluntary EV rate options to encourage residential customers who purchase or lease EVs to charge them during off-peak periods. The Pilot program provides two rate options. One rate option, a "whole house" rate, allows customers to apply the time-of-use rate to their entire service, including their premises and vehicle. The other rate option, an "EV only" rate, allows customers to remain on their existing standard rate for their premises and subscribe to the time-of-use rate only for their vehicle. The program is open to up to 1,500 residential customers, with up to 750 in each of the two experimental rates. Additional information regarding the Company's EV Pilot Program is available in the Company's application and in the SCC's Order Granting Approval.

Current Pilot Status:

The SCC approved the Pilot on July 11, 2011. The Company began Pilot enrollment October 3, 2011, and will conclude the Pilot by November 30, 2014. As of June 2013, 148 customers were enrolled on the whole-house EV rate while 34 customers were enrolled on the EV-only rate.

Additional information regarding the Pilot is available at:
https://www.dom.com/about/environment/electric-vehicles.jsp.

AMI Upgrades

State:	Virginia
Target Class:	All-Classes
Type:	Energy Efficiency
Duration:	Ongoing

Meter Upgrades

The Company continues to upgrade meters to Advanced Metering Infrastructure, also referred to as smart meters. The AMI meter upgrades are part of an on-going project that will help the Company further evaluate the technology and verify the potential impacts to its system.

Description:

The Company indicated in its supplemental testimony filed with the SCC on February 12, 2010 (Case No. PUE-2009-00081) that it wanted to obtain further information regarding AMI to ensure that the technology, costs and benefits of implementing the technology, and the technology's potential for energy reduction were better understood. To date, the Company has installed over 135,000 smart meters on homes and businesses in areas throughout Virginia. Additional information about smart meter technology is available at www.dom.com/smartmeter.

3.2.4 CURRENT CONSUMER EDUCATION PROGRAMS

The Company's consumer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption. The Company's website has a section dedicated to energy conservation. This section contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Through consumer education, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina. Examples of how the Company increases customer awareness include:

Customer Connection Newsletter
State: Virginia and North Carolina
The Customer Connection newsletter is sent to customers as an insert to their monthly power bill six times per year. It contains news on topics such as DSM programs, how to save money or manage electric bills, helping the environment, service issues, and safety recommendations, in addition to many other relevant subjects. For those who receive their electric bills by e-mail, the newsletter is available online. Articles from the most recent Virginia Customer Connection Newsletter are located on the Company's website at http://www.dom.com/dominion-virginia-power/customer-service/your-bill/customer-connection.jsp. Articles from the most recent North Carolina Customer Connection Newsletter are located on the Company's website at: http://www.dom.com/dominion-north-carolina-power/customer-service/your-bill/customer-connection.jsp.

Energy Conservation Blog
State: Virginia and North Carolina
The Company has an "Energy Conservation Blog," which is an online forum for Company experts to answer customer questions on energy-related topics and provide specific examples of measures to take that will help reduce energy consumption. It is also a means to provide information about the Company's DSM programs. The blog is online at: http://e-conserve.blogspot.com/.

Twitter ® and Facebook
State: Virginia and North Carolina
The Company uses the social media channels of Twitter® and Facebook to provide real-time updates on energy-related topics, promote Company messages, and provide two-way communication with customers.

The Twitter® account is available online at: www.twitter.com/DomVAPower.
The Facebook account is available online at: http://www.facebook.com/dominionvirginiapower.

"Every Day"
State: Virginia
The Company advertises the "Every Day" campaign, which is a series of commercial and print ads that address various energy issues. These advertisements, along with the Company's other advertisements, are available at: http://www.dom.com/about/advertising/index.jsp.

News Releases
State: Virginia and North Carolina
The Company prepares news releases and reports on the latest developments regarding its DSM initiatives and provides updates on Company offerings and recommendations for saving energy as new information becomes available. Current and archived news releases can be viewed at: http://www.dom.com/news/index.jsp.

Online Energy Calculators

State: Virginia and North Carolina

Home and business energy calculators are provided on the Company's website to estimate electrical usage for homes and business facilities. The calculators can help customers understand specific energy use by location and discover new means to reduce usage and save money. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at: http://www.dom.com/about/conservation/energy-calculators-help-find-energy-savings.jsp.

Community Outreach - Trade Shows, Exhibits and Speaking Engagements

State: Virginia and North Carolina

The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation information to both internal and external audiences. The Company also participates in various trade shows and exhibits at energy-related events to inform customers and communities about the importance of implementing energy-saving measures in homes and businesses. Additionally, Company representatives positively impact the communities served through presentations to elementary, middle, and high school students about using energy wisely and environmental stewardship.

The Company also provides helpful materials for students to share with their families. Project Plant It! is an innovative program available to elementary school students in Virginia, North Carolina, Connecticut, Maryland, Pennsylvania, and New York that teaches students about the importance of trees and how to protect the environment. This program includes interactive classroom lessons and provides students with tree seedlings to plant at home or at school. The Company offers Project Plant It! free of charge throughout the Company's service territory and, thus far, has distributed more than160,000 seedlings to elementary school students through the program since 2007.

DSM Program Communications

The Company uses numerous methods to make customers aware of its DSM Programs. These methods include direct mail, communications through contractor networks, e-mail, radio ads, social media, and outreach events.

3.2.5 APPROVED AND EXTENDED DSM PROGRAMS

In Virginia, the Company filed for SCC approval of 12 DSM Programs ("DSM Programs") on July 28, 2009 (Case No. PUE-2009-00081). On March 24, 2010, the SCC issued its Final Order approving five of the 11 proposed Programs including the: i) Air Conditioner Cycling Program, ii) Commercial Heating, Ventilating, and Air Conditioning ("HVAC") Upgrade Program, iii) Commercial Lighting Program, iv) Low Income Program, and v) Residential Lighting Program.

On March 11, 2010, the NCUC issued an Order requiring the Company to file for approval of demand response programs on or before September 1, 2010 (Docket No. E-22, Sub 418). The

Company filed for approval of six DSM Programs in North Carolina on September 1, 2010, in Docket No. E-22, Subs 465 (Air Conditioner Cycling Program), 466 (CDG Program), 467 (Commercial HVAC Upgrade Program), 468 (Residential Lighting Program), 469 (Commercial Lighting Program), and 463 (Low Income Program), two of which (Air Conditioner Cycling and CDG Programs) were demand response to comply with the directives of the NCUC March 11, 2010 Order. These six proposed Programs were similar to the Programs approved in the Company's 2009 Virginia filing, with the exception of the CDG Program, which was not approved in its initial form by the SCC.

On February 22, 2011, the NCUC issued Final Orders approving five Programs, the: i) Air Conditioner Cycling Program, ii) Commercial HVAC Upgrade Program, iii) Commercial Lighting Program, iv) Low Income Program, and v) Residential Lighting Program. On September 14, 2011, the NCUC issued an order denying the approval of the CDG Program.

On September 1, 2011, the Company filed, in Virginia, for SCC approval of six new DSM Programs (Case No. PUE-2011-00093). The six proposed Programs were the i) Commercial Energy Audit Program, ii) Commercial Duct Testing & Sealing Program, iii) Commercial Refrigeration Program, iv) the re-designed Commercial Distributed Generation ("CDG") Program, v) Residential Lighting (Phase II) Program, and vi) Residential Bundle Program. The Residential Bundle Program consisted of: i) Residential Home Energy Check-Up Program, ii) Residential Duct Testing & Sealing Program, iii) Residential Heat Pump Tune-Up Program, and iv) Residential Heat Pump Upgrade Program. The Residential Bundle Program was studied for cost-effectiveness as one Program.

As of December 31, 2011, the Residential Lighting (Phase 1) Program has concluded in both Virginia and North Carolina in large part due to increased bulb efficiency standards that became effective January 1, 2012, as mandated by the Energy Independence and Security Act of 2007. No incentives have been offered under this Program after December 31, 2011.

On April 30, 2012, the SCC issued its Final Order in Case No. PUE-2011-00093 approving all of the proposed Programs except the Commercial Refrigeration and Residential Lighting (Phase II) Programs, which the SCC found not to be in the public interest. The SCC did grant the Company the ability to incorporate a measure, the condenser coil cleaning measure, from the Commercial Refrigeration Program into the approved Commercial Energy Audit Program.

Additionally, as part of its Final Order in Case No. PUE-2011-00093, the SCC, denied as not being in the public interest, the Company's request for additional program funding for the Commercial HVAC and Commercial Lighting Programs. As a result, the Company concluded the Commercial HVAC and Commercial Lighting Programs to new participants in Virginia in July 2012 and suspended them to new participants in North Carolina on August 16, 2012. After these Programs were suspended in North Carolina, the Company continued to study its ability to reinitiate the Programs only in its North Carolina service territory on a cost-effective basis.

The Company also studied its ability to bring new future non-residential lighting, heating and cooling programs on a system-wide basis.

On August 31, 2012, the Company filed a petition in Case No. PUE-2012-00100 for SCC approval to extend two previously-approved DSM programs, the Low Income Program and the Air Conditioner Cycling Program, for a period of two and five years, respectively, subject to future extensions as requested and granted by the SCC. In its April 19, 2013 Order in the proceeding, the SCC, among other things, approved a two-year extension of the Low Income Program and a three-year extension of the Air Conditioner Cycling Program.

Appendix 3M provides program descriptions for the currently approved and extended DSM Programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and plans to achieve each Program's penetration goals. Appendices 3N, 3O, 3P and 3Q provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved and extended Program.

3.2.6 PROPOSED DSM PROGRAMS

The Commonwealth of Virginia has an energy reduction target for 2022 of reducing the consumption of electric energy by retail customers by an amount equal to 10% of the amount of electric energy consumed by retail customers in 2006, as applied to the Company's 2006 jurisdictional retail sales. The Company has expressed its commitment to helping Virginia reach this goal. Related to and consistent with the goal, DSM Programs are an important part of the Company's portfolio available to meet customers' growing need for electricity along with supply-side resources.

On August 30, 2013, as part of Case No. PUE-2013-00072, the Company filed in Virginia for SCC approval of three new DSM Programs ("Phase III DSM Programs"). The three Programs are: the Non-Residential Lighting Systems & Controls Program, the Non-Residential Heating & Cooling Efficiency Program, and the Non-Residential Solar Window Film Program. All three Programs are classified as energy efficiency programs, as that classification is defined under Va. Code § 56-576. In addition, the Company is requesting the addition of measures to enhance the approved Non-Residential Energy Audit Program.

In North Carolina, in Docket Nos. E-22, Subs 495, 496, 497, 498, 499, 500, the Company filed for NCUC approval of six new DSM Programs ("Phase II DSM Programs"). These Programs are the same Phase II DSM Programs that were approved in Virginia in Case No. PUE-2011-00093, with the exception of the CDG Program, which had been denied approval in North Carolina in 2011. The Non-Residential Energy Audit Program is being proposed with enhancements to the Program approved in Virginia in 2012, consistent with the Company's request in Virginia. Additionally, in Docket Nos. E-22, Sub 467 and 469, respectively, the

Company filed for NCUC approval to reinitiate the Commercial HVAC and Commercial Lighting Programs on a North Carolina-only basis.

Appendices 3R, 3S, 3T and 3U provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each of the Virginia Proposed Programs.

3.2.7 EVALUATION, MEASUREMENT & VERIFICATION

The Company has implemented EM&V plans to quantify the level of energy and demand savings for approved Programs in Virginia and North Carolina. As required by the SCC and NCUC, the Company will provide annual EM&V reports that include: i) the actual EM&V data; ii) the cumulative results for each Program in comparison to forecasted annual projections; and iii) any recommendations or observations following the analysis of the EM&V data. These annual reports will be filed on April 1 in each jurisdiction and will provide information through the prior calendar year. DNV KEMA Energy & Sustainability ("KEMA"), a third-party vendor, continues to be responsible for developing, executing, and reporting the EM&V results for the Company's currently approved DSM Programs.

3.3 TRANSMISSION RESOURCES

3.3.1 EXISTING TRANSMISSION RESOURCES

The Company has over 6,400 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV. These facilities are integrated into PJM.

3.3.2 EXISTING TRANSMISSION & DISTRIBUTION LINES

North Carolina Plan Addendum 2 contains the list of Company's existing transmission and distribution lines listed in pages 422, 423, 424, 425, 426 and 427, respectively, of the Company's most recently filed Federal Energy Regulatory Commission ("FERC") Form 1.

3.3.3 TRANSMISSION PROJECTS UNDER CONSTRUCTION

The Company currently has two transmission interconnection projects under construction which may be found in Appendix 3W. A list of the Company's transmission lines and associated facilities that are under construction may be found in Appendix 3X.

Chapter 4 | Planning Assumptions

CHAPTER 4 – PLANNING ASSUMPTIONS

4.1 PLANNING ASSUMPTIONS INTRODUCTION

The Company's 2013 Plan relies upon a number of assumptions including requirements from PJM. Chapter 4 covers a diverse set of these assumptions and requirements related to capacity needs, reserve requirements, renewable energy requirements, commodity price assumptions, and transmission assumptions. The Company updates its IRP assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.2 PJM CAPACITY PLANNING PROCESS & RESERVE REQUIREMENTS

The Company participates in the PJM capacity planning processes for short- and long-term capacity planning. A brief discussion of these processes and the Company's participation in them is provided in the following subsections.

4.2.1 SHORT-TERM CAPACITY PLANNING PROCESS – RPM

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines. PJM then conducts a capacity auction through its Short-Term Capacity Planning Process ("RPM auction") for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the delivery year that is three years in the future (2013 auction will procure capacity for the delivery year 2016/2017).

The Company, as a generation provider, bids its capacity resources, including owned and contracted generation and DSM programs, into this auction. The Company, as an LSE, is obligated to buy enough capacity to cover its capacity requirements from the RPM auction, or through any bilateral trades. Figure 4.2.2.1 provides the Company's estimated 2014 to 2016 capacity positions and associated reserve margins based on PJM's January 2013 Load Forecast and RPM auctions that have already been conducted.

4.2.2 LONG-TERM CAPACITY PLANNING PROCESS – RESERVE REQUIREMENTS

The Company uses PJM's reserve margin guidelines in conjunction with its own load forecast discussed in Chapter 2 to determine its long-term capacity requirement. PJM conducts an annual Reserve Requirement Study to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a Loss of Load Expectation ("LOLE") that is equivalent to one day of outage in 10 years. PJM's 2012 Reserve Requirement Study[5] for delivery year 2016/2017, recommends using a reserve margin of 15.6% to satisfy the NERC/Reliability First Corporation ("RFC") Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation.

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[5] PJM's current and historical reserve margins are available at: http://www.pjm.com/sitecore%20modules/web/~/media/planning/res-adeq/historical-pjm-installed-reserve-margin.ashx.

Three assumptions were made by the Company when applying the PJM reserve margin to the Company's modeling efforts. First, since PJM uses a shorter planning period than the Company, the Company took the most recent reserve requirements study and assumed the reserve margin value for the year indicated would continue throughout its Study Period. Second, PJM develops reserve margin estimates for planning years (referred to as delivery in RPM) rather than calendar years. Specifically, PJM's planning year occurs from June 1st of one year to May 31st of the following year. Since the Company and PJM are both historically summer peaking entities, and since the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer time-period. For example, the Company uses the 2016/2017 planning year assumptions for the 2016 calendar year in its 2013 Plan where, in both instances, reserves are determined for the expected peak load during the summer of 2016.

The final assumption is in regard to the coincident factor between the DOM Zone coincidental and non-coincidental peak load. The Company is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load. Since the Company's peak load (non-coincidental) has not historically occurred during the same hour as PJM's peak load (coincidental), a smaller reserve margin is needed to meet reliability targets and is based on a coincidence factor. To determine the coincidence factor used in the 2013 Plan, the Company used a four-year (2013-2016) average of the coincidence factor between the DOM Zone coincidental and non-coincidental peak load. The coincidence factor for the Company's load is approximately 96.2% as calculated using PJM's January 2013 Load Forecast. In 2016, applying the PJM Installed Reserve Margin ("IRM") requirement of 15.6% with the Company's coincidence factor of 96.2% resulted in an effective reserve margin of 11.2% as shown in Figure 4.2.2.1. This effective reserve margin was then used for each year for the remainder of the Planning Period.

As a member of PJM, the Company participates in the annual RPM capacity markets. PJM's RPM construct has historically resulted in a clearing reserve margin in excess of the planned reserve margin requirement. The PJM RPM clearing reserve margin has averaged 20.4% over the past five years.[6] Using the same techniques described above, this equates to an approximate 15.78% effective reserve requirement. With the RPM clearing capacity in excess of its target level, the Company has purchased reserves in excess of the 11.2% planning reserve margin as reflected in Figure 4.2.2.1. Given this history, Figures 1.4.3(a) and (b) and 6.8.3(a) and (b), display a second capacity requirement target including an additional 5% reserve requirement target (16.2% reserve margin) that is commensurate with the upper bound where the RPM market has historically cleared; however, the Company's planning reserve margin minimum target remains at 11.2%. The upper bound reserve margin is being shown in this 2013 Plan to reflect the reserve margin that the Company may be required to meet in the future.

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[6] *See* http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx.

Figure 4.2.2.1 PEAK LOAD FORECAST & RESERVE REQUIREMENTS

Year	PJM Installed Reserve Margin Requirements[1]	DVP Effective Reserve Margin	Total System Summer Peak[2]	Reserve Requirement	Total Resource Requirement[3]
	%	%	MW	MW	MW
2014	-	17.6%	17,244	3,043	20,287
2015	-	16.9%	17,695	2,999	20,694
2016	-	15.8%	18,070	2,847	20,917
2017	15.6%	11.2%	18,351	2,049	20,400
2018	15.6%	11.2%	18,578	2,102	20,680
2019	15.6%	11.2%	18,825	2,133	20,958
2020	15.6%	11.2%	19,106	2,165	21,271
2021	15.6%	11.2%	19,391	2,196	21,587
2022	15.6%	11.2%	19,665	2,228	21,893
2023	15.6%	11.2%	19,955	2,261	22,216
2024	15.6%	11.2%	20,248	2,293	22,541
2025	15.6%	11.2%	20,538	2,327	22,865
2026	15.6%	11.2%	20,836	2,362	23,198
2027	15.6%	11.2%	21,151	2,394	23,545
2028	15.6%	11.2%	21,439	2,394	23,832

Notes: 1) 2014 – 2016 values reflect the Company's position following RPM base residual auctions that have cleared.
2) Does not include conservation/efficiency adjustments.
3) Includes wholesale obligations.

In Figure 4.2.2.1, the total resource requirement column provides the total amount of peak capacity including the reserve margin used in the 2013 Plan. This represents the Company's total resource need that must be met through existing resources, construction of new resources, DSM programs, and market capacity purchases. Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions and annually updated load and reserve requirements. Appendix 2I provides a summary of projected PJM reserve margins for summer peak demand.

Finally, the industry's compliance with effective and anticipated EPA regulations concerning air, water, and solid waste constituents will likely cause a significant number of coal plants to retire during the 2014 through 2016 time period. Therefore, the Company maintains that it is prudent to plan for a higher capacity reserve margin during this period of uncertainty and not expose its customers to an overreliance on market purchases during this uncertain period of time.

4.3 RENEWABLE ENERGY

4.3.1 VIRGINIA RPS PLAN

On May 18, 2010, the SCC issued its Final Order granting the Company's July 28, 2009 application to participate in Virginia's voluntary Renewable Energy Portfolio Standards ("RPS") program finding that "the Company has demonstrated that it has a reasonable expectation of achieving 12 percent of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15 percent of its base year electric energy sales from renewable energy sources during calendar year 2025" (Case No. PUE-2009-00082, May 18, 2010 Final Order at 7). The RPS requirements prescribe that a certain percent of the Company's energy should be obtained from renewable resources. The Company can meet Virginia's RPS program guidelines through the generation of renewable energy, purchase of renewable energy, purchase of renewable energy certificates ("RECs"), or a combination of the three options. The Company achieved its 2012 Virginia RPS Goal. Figure 4.3.1.1 displays Virginia's RPS goals.

Figure 4.3.1.1 VIRGINIA RPS GOALS

Year	Percent of RPS	Annual GWh[1]
2010	4% of Base Year Sales	1,733
2011-2015	Average of 4% of Base Year Sales	1,733
2016	7% of Base Year Sales	3,032
2017-2021	Average of 7% of Base Year Sales	3,032
2022	12% of Base Year Sales	5,198
2023-2024	Average of 12% of Base Year Sales	5,198
2025	15% of Base Year Sales	6,497

***Note:** 1) Base year sales are equal to 2007 Virginia jurisdictional retail sales, minus 2004 to 2006 average nuclear generation. Actual goals are based on MWh.*

The Company has included renewable resources as an option in Strategist, taking into consideration the economics and RPS requirements. VCHEC, now operational, is expected to initially provide up to 6 MW of biomass capacity which is projected to increase to 60 MW by 2020. Plan B: Fuel Diversity Plan also identifies 247 MW (nameplate) of onshore wind and 200 MW (nameplate) of solar capacity and 20 MW (nameplate) solar tag. The Base Plan and Fuel Diversity Plan also include a 20 MW biomass, 15 MW solid waste and 50 MW (nameplate) solar NUGs (Figure 4.3.1.2). The Company reiterates its intent to meet Virginia's RPS guidelines at a reasonable cost and in a prudent manner by: i) applying renewable energy from existing generating facilities including NUGs; ii) purchasing cost-effective RECs (including optimizing RECs produced by Company-owned generation when these higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS goals); and iii) constructing new renewable resources when and where feasible.

4.3.2 NORTH CAROLINA REPS PLAN

NCGS § 62-133.8 requires the Company to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Plan requirement. The REPS requirements can be met by generating renewable energy, energy efficiency measures (capped at 25% of the REPS requirements through 2020 and up to 40% thereafter), purchasing renewable energy, purchasing RECs, or a combination of options as permitted by NCGS § 62-133.8 (b) (2). The Company plans to meet a portion of the general REPS requirements using the approved energy efficiency programs discussed in Chapter 3 and 6 of this Plan. The Company achieved compliance with its 2012 North Carolina REPS requirements by using banked RECs and purchasing additional qualified RECs. In addition, the Company purchased sufficient RECs to comply with the poultry waste requirement. However, on November 29, 2012, in response to the Amended Joint Motion to Delay, the NCUC eliminated the 2012 swine waste requirement and delayed the poultry waste requirement for a one-year period. More information regarding the Company's plans is available in its North Carolina REPS Compliance Plan filed in North Carolina with this 2013 Plan as North Carolina IRP Addendum 1. Figure 4.3.2.1 displays North Carolina's overall REPS requirements.

Figure 4.3.2.1 NORTH CAROLINA REPS REQUIREMENTS

Year	Percent of REPS	Annual GWh[1]
2012	3% of 2011 DNCP Retail Sales	125
2013	3% of 2012 DNCP Retail Sales	123
2014	3% of 2013 DNCP Retail Sales	125
2015	6% of 2014 DNCP Retail Sales	253
2016	6% of 2015 DNCP Retail Sales	258
2017	6% of 2016 DNCP Retail Sales	260
2018	10% of 2017 DNCP Retail Sales	435
2019	10% of 2018 DNCP Retail Sales	438
2020	10% of 2019 DNCP Retail Sales	443
2021	12.5% of 2020 DNCP Retail Sales	562

Note: 1) Annual gigawatt hour is an estimate only based on the latest forecast sales. The Company intends to comply with the North Carolina REPS requirements, including the set-asides for energy derived from solar, poultry litter, and swine waste through the purchase of RECs and/or purchased energy, as applicable. These set aside requirements represent approximately 0.03% of system load by 2024 and will not materially alter the 2013 Plan.

As part of the total REPS requirements, North Carolina requires certain renewable set aside provisions for solar energy, swine waste, and poultry waste resources as shown in Figure 4.3.2.2, Figure 4.3.2.3, and Figure 4.3.2.4.

Figure 4.3.2.2 NORTH CAROLINA SOLAR REQUIREMENTS

Year	Requirement Target (%)	Annual GWh[1]
2010	0.02% of 2009 DNCP Retail Sales	0.81[2]
2011	0.02% of 2010 DNCP Retail Sales	0.87[2]
2012	0.07% of 2011 DNCP Retail Sales	2.93[3]
2013	0.07% of 2012 DNCP Retail Sales	2.89
2014	0.07% of 2013 DNCP Retail Sales	2.92
2015	0.14% of 2014 DNCP Retail Sales	5.91
2016	0.14% of 2015 DNCP Retail Sales	6.01
2017	0.14% of 2016 DNCP Retail Sales	6.07
2018	0.20% of 2017 DNCP Retail Sales	8.70
2019	0.20% of 2018 DNCP Retail Sales	8.76
2020	0.20% of 2019 DNCP Retail Sales	8.86
2021	0.20% of 2020 DNCP Retail Sales	8.99

Notes: *1) Annual gigawatt hour is an estimate based on latest forecast sales.*
2) The Company achieved compliance with the 2010 - 2012 NC Solar targets.
3) The Company has purchased solar RECs necessary to satisfy the North Carolina 2013 solar goal of 2.89 GWh.

Figure 4.3.2.3 NORTH CAROLINA SWINE WASTE REQUIREMENTS

Year	Target	Dominion Market Share (Est.)	Annual GWh[1]
2012	Requirement Eliminated	3.19%	
2013	0.07% of 2012 NC Retail Sales	3.22%	2.88
2014	0.07% of 2013 NC Retail Sales	2.91%	2.92
2015	0.14% of 2014 NC Retail Sales	2.90%	5.91
2016	0.14% of 2015 NC Retail Sales	2.90%	6.01
2017	0.14% of 2016 NC Retail Sales	2.88%	6.07
2018	0.20% of 2017 NC Retail Sales	2.84%	8.70
2019	0.20% of 2018 NC Retail Sales	2.82%	8.76
2020	0.20% of 2019 NC Retail Sales	2.80%	8.86
2021	0.20% of 2020 NC Retail Sales	2.80%	8.99

Note: *1) Annual gigawatt hour is an estimate based on the latest forecast sales.*

Figure 4.3.2.4 NORTH CAROLINA POULTRY WASTE REQUIREMENTS

Year	Target[1] (GWh)	Dominion Market Share (Est.)	Annual GWh[2]
2012	Requirement Delayed	3.19%	
2013	170	3.22%	22.54
2014	700	2.91%	26.22
2015	900	2.90%	26.08
2016	900	2.90%	26.09
2017	900	2.88%	25.93
2018	900	2.84%	25.58
2019	900	2.82%	25.35
2020	900	2.80%	25.22
2021	900	2.80%	25.18

Note: 1) For purposes of this filing, the Poultry Waste Resource requirement is calculated as an aggregate target for NC electric suppliers distributed based on market share.

4.4 COMMODITY PRICE ASSUMPTIONS

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analysis for the 2013 Plan using energy and commodity price forecasts provided by ICF International, Inc. ("ICF"), a global energy consulting firm, in all periods except the first 36 months of the Study Period. The forecast used forward market prices, as of May 31, 2013, for natural gas, coal, and power prices for the first 18 months and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity prices, CO_2, NO_x, and SO_2 allowance prices are provided by ICF for all years forecast in this year's Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM auction through the 2016/2017 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2017/2018 delivery year. The CO_2 price forecast begins in 2023 to reflect the potential for regulations or legislation covering CO_2 emissions from the power sector.

4.4.1 BASECASE COMMODITY FORECAST

The basecase commodity forecast represents what the Company views as the most likely outcome for commodity prices given current market conditions and ICF's independent internal views of key market drivers. Key drivers include market structure and policy elements that shape allowance, fuel and power markets, ranging from expected capacity and pollution control installations, environmental regulations, and fuel supply-side issues. The basecase commodity forecast provides a forecast of prices for fuel, energy, capacity, emission allowances and RECs. The methodology used to develop the forecast relies on an integrated, internally consistent, fundamentals-based analysis. The development process assesses the impact of environmental regulations on the power and fuel markets and incorporates ICF's latest views on the outcome of new regulatory initiatives.

A summary of the basecase fuel price forecast is provided in the charts below including comparison to the prices used in the 2012 Plan. Extraordinarily Sensitive Appendix 4A provides the annual prices forecast for each key commodity in the basecase. Extraordinarily Sensitive Appendix 4C provides delivered fuel prices and primary fuel expense from the Strategist model output using the basecase forecast. Extraordinarily Sensitive Figures 4.4.1.1, 4.4.1.2, and 4.4.1.3 display the basecase fuel price forecasts, while Extraordinarily Sensitive Figures 4.4.1.4 and 4.4.1.5 display the forecasted price for SO_2, NO_x, and CO_2 emissions allowances on a dollar per ton basis. Extraordinarily Sensitive Figure 4.4.1.6 presents the forecasted market clearing power prices for the PJM DOM Zone. The forecast of PJM RTO capacity price is presented in Extraordinarily Sensitive Figure 4.4.1.7.

*****EXTRAORDINARILY SENSITIVE INFORMATION REDACTED*****

Figure 4.4.1.1 FUEL PRICE FORECASTS - NATURAL GAS

[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

Figure 4.4.1.2 FUEL PRICE FORECASTS - COAL

[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

Figure 4.4.1.3 FUEL PRICE FORECASTS - OIL

[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

Figure 4.4.1.4 PRICE FORECASTS – SO_2 & NO_X

[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

Figure 4.4.1.5 PRICE FORECASTS - CO_2

[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

Figure 4.4.1.6 POWER PRICE FORECASTS

[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

Figure 4.4.1.7 PJM RTO CAPACITY PRICE FORECASTS

[redacted]

As seen in the above Figures, there are multiple differences in the 2013 basecase forecast used in this Plan compared to the basecase forecast used in 2012 Plan. In general, the forecast prices are lower relative to the 2012 Plan. The primary changes include lower natural gas and coal prices and updated environmental assumptions reflecting ICF's latest views on final and proposed environmental rules. The lower power prices are primarily due to lower fuel cost. Over the long-term, the lower price outlook for natural gas is a result of continued increases in production from shale gas development in North America. The outlook for coal prices are lower based on significantly lower Central Appalachian ("CAPP") demand than predicted in last year's forecast due to coal plant retirements and remaining coal plants switching to lower quality, lower cost coals. Extraordinarily Sensitive Figure 4.4.1.8 presents a comparison of average fuel, electric, and REC prices used in the 2012 Plan relative to those used in the 2013 Plan.

The capacity price outlook in this year's forecast is lower as the forecast incorporates the results of the 2016/2017 RPM auction in which RTO prices dropped significantly relative to 2015/2016 results. Although ICF does not believe that the latest auction results are indicative of the cost recovery necessary under equilibrium conditions, they do believe that certain trends and behaviors will continue in the near term, particularly given uncertainties in capacity market rules going forward. The price forecast continues to be influenced by these market aspects into the mid-term. ICF's capacity forecast does reflect the retirement of resources and the tightening of demand side participation rules in the PJM capacity market.

*****EXTRAORDINARILY SENSITIVE INFORMATION REDACTED*****

Figure 4.4.1.8 2012 TO 2013 PLAN FUEL & POWER PRICE COMPARISON

	Planning Period Comparison - Average Values (2012 Real $)	
Fuel Price	2012 Plan Basecase[3]	2013 Plan Basecase[3]
Henry Hub Natural Gas[1] ($/MMbtu)	[redacted]	[redacted]
DOM Zone Delivered Natural Gas[1] ($/MMbtu)	[redacted]	[redacted]
CAPP CSX 12,500 1%S FOB ($/MMbtu)	[redacted]	[redacted]
No. 2 Oil ($/MMbtu)	[redacted]	[redacted]
1% No. 6 Oil ($/MMbtu	[redacted]	[redacted]
Electric and REC Prices	[redacted]	[redacted]
PJM-DOM On-Peak ($/MWh)	[redacted]	[redacted]
PJM-DOM Off-Peak ($/MWh)	[redacted]	[redacted]
PJM Tier 1 REC Prices ($/MWh)	[redacted]	[redacted]
RTO Capacity Prices[2] ($/KW-yr)	[redacted]	[redacted]

Note: 1) DOM Zone natural gas price used in plan analysis. Henry Hub prices are shown to provide market reference.
2) Capacity price represents actual clearing price from PJM Reliability Pricing Model Base Residual Auction results through power year 2015/2016 for 2012 Plan and 2016/2017 for 2013 Plan.
3) 2012 Planning period 2013 – 2027, 2013 Planning Period 2014 – 2028.

4.4.2 ALTERNATIVE SCENARIO COMMODITY PRICES

The alternative commodity price forecast scenarios represent reasonable outcomes for future commodity prices based on alternate views of key fundamental drivers of commodity prices. However, as with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity price scenarios developed for this year's Plan. History has shown that unforeseen events can result in significant change in market fundamentals. These events were not contemplated five or ten years before such an occurrence. Several recent examples include the shale gas revolution that is transforming the pricing structure of natural gas, a commodity that as recently as 2008, was priced at historically high levels. Another recent example is the scheduled retirement of numerous generation units fueled primarily by coal in response to low gas prices, an ageing coal fleet, and environmental compliance cost. The effects of unforeseen events should be considered when evaluating the viability of long term planning objectives. The commodity price forecast scenarios analyzed for the Plan present reasonable outcomes given the current understanding of market fundamentals, but not all possible outcomes. Considering the potential for unforeseen events, such as those discussed above, the Company considers the preservation of generation options, including renewable and nuclear, as a necessary tool in a prudent long-term planning process.

The Company performed analyses using three alternative pricing scenarios. The methodology of using scenarios in IRP planning is further explained in Section 6.6 herein. The scenarios used in the analysis include (1) High Fuel Cost, (2) Low Fuel Cost, and (3) No CO_2 Cost.

The High Fuel Cost scenario was developed to assess a possible future where key market drivers create upward pressure on commodity and energy prices during the Planning Period. This scenario reflects a correlated increase in commodity prices which, when compared to the basecase, provides an increase of approximately 12% for natural gas, 36% for No. 2 oil, 18% for coal, and 8% higher PJM-DOM Zone peak energy prices during the Planning Period. The drivers behind these price movements include lower incremental production growth from shale gas reservoirs, along with higher costs to locate and produce natural gas. Higher prices for coal are driven by increasing production costs due to increased safety requirements, more difficult geology, and higher stripping ratios. Extraordinarily Sensitive Appendix 4B provides the annual prices used in the High Fuel Cost scenario.

The Low Fuel Cost scenario was developed to assess a possible future where key market drivers create downward pressure on commodity and energy prices during the Planning Period. This scenario reflects a correlated price decrease in natural gas that averages approximately 10%, No. 2 oil price decrease of 5%, coal price drops by approximately 11%, and 7% lower PJM-DOM Zone peak energy prices across the Planning Period when compared to the basecase. The drivers behind these price movements include higher incremental production growth from shale gas reservoirs, lower costs to locate and produce natural gas, lower gross domestic product growth in developing countries, and improved coal mining productivity.

Extraordinarily Sensitive Appendix 4B provides the annual prices used in the Low Fuel Cost scenario.

In the No CO_2 Cost scenario, the cost associated with future carbon emissions is removed from the forecast. The cost of carbon being removed has an effect on certain fuels across the Planning Period, resulting in an 8% decrease in natural gas price and no appreciable change in coal or oil prices. PJM-DOM Zone peak energy prices are on average 8% lower than the basecase. Specifically, when compared to the basecase, the PJM-DOM Zone peak energy price in the No CO_2 Cost scenario is 12% lower between 2023, when the basecase assumes CO_2 regulation would begin, and the end of the Planning Period. Extraordinarily Sensitive Appendix 4B provides the annual prices used in the No CO_2 Cost scenario.

Extraordinarily Sensitive Figure 4.4.2.1 provides a comparison of the three alternative scenarios to the basecase forecast.

*****EXTRAORDINARILY SENSITIVE INFORMATION REDACTED*****

Figure 4.4.2.1 2013 PLAN SCENARIOS FUEL & POWER PRICE COMPARISON

	2014 - 2028 Average Values (2012 Real $)			
Fuel Price	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
Henry Hub Natural Gas ($/MMbtu)	[redacted]			
DOM Zone Delivered Natural Gas ($/MMbtu)				
CAPP CSX 12,500 1%S FOB ($/MMbtu)				
No. 2 Oil ($/MMbtu)				
1% No. 6 Oil ($/MMbtu				
Electric and REC Prices				
PJM-DOM On-Peak ($/MWh)				
PJM-DOM Off-Peak ($/MWh)				
PJM Tier 1 REC Prices ($/MWh)				
RTO Capacity Prices ($/KW-yr)				

4.5 DEVELOPMENT OF DSM PROGRAM ASSUMPTIONS

The Company develops assumptions for the DSM programs in a two-step process. First, ICF is employed to develop assumptions for programs that may be good candidates for acceptance on the Company's system. Second, the Company tests the market through a RFP process to find vendors that can deliver the individual energy efficiency measures in the marketplace.

The ICF process includes evaluating either a single measure program like the Residential Heat Pump Tune-Up Program or a multi-measure program like the Non-Residential Energy Audit Program. For all measures in a program, ICF develops a baseline for a standard customer end-use technology. The baseline establishes the current energy usage for a particular appliance or customer end-use. Next, assumptions for a more efficient replacement measure or end-use are developed. The difference between the more efficient energy end-use and the standard end-use provides the incremental benefit that the Company and customer will achieve if the more efficient energy use is implemented.

ICF's development of assumptions for a DSM program includes determining cost estimates for the incremental customer investment in the more efficient technology, the incentive the Company must pay the customer to encourage investment in the DSM measure, and the program cost the Company must incur to administer the program (both vendor payments and common program costs). In addition to the cost assumptions for the program, ICF develops incremental demand and energy reductions associated with the program. This data is represented in the form of a load shape for energy efficiency programs which identifies the energy reductions by hour for each hour of the year (8,760 hour load shape).

The Company then uses the program assumptions developed by ICF to perform cost/benefit tests for the programs. The cost/benefit tests assist in determining which programs are cost-effective and potentially included in the Company's DSM portfolio. Programs that pass the Company's screening process are then assessed using a RFP process. The bid process results in a list of vendors who are qualified to deliver the proposed DSM programs. The Company evaluates all bids and selects the vendor(s) that are best qualified to deliver the portfolio of DSM programs.

4.6 TRANSMISSION PLANNING

The Company's transmission planning process, system adequacy, transfer capabilities, and transmission interconnection process are described in the following subsections. As used in this Plan, electric transmission facilities at the Company can be generally defined as those operating at 69 kV and above that connect sources of power with distribution facilities and provide for the interchange of power within and outside of the Company's transmission network.

4.6.1 REGIONAL TRANSMISSION PLANNING & SYSTEM ADEQUACY

The Company's transmission system is designed and operated to ensure adequate and reliable service to its customers while meeting all regulatory requirements and standards. Specifically, the Company's transmission system is developed to comply with the NERC Reliability Standards, as well as the Southeastern Reliability Corporation supplements to the NERC standards.

The Company participates in numerous regional, interregional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is a member of PJM, a RTO responsible for the movement of wholesale electricity. PJM is registered with NERC as the Company's Planning Coordinator and Transmission Planner. Accordingly, the Company participates in the PJM Regional Transmission Expansion Plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a five-year and 15-year outlook. Specifically, for short-term planning, the five-year outlook enables the Company to meet near-term load growth.

The Company evaluates its ability to support expected customer growth through its internal planning process. The results of this evaluation indicate transmission improvements are needed, which the Company generally includes in the PJM RTEP process and, if the need is confirmed, then seeks approval from the appropriate regulatory body. Additionally, the Company performs seasonal operating studies to identify facilities in the Company's transmission system that could be critical during the upcoming season. Due to the regional nature of many transmission projects, the Company shares in the cost and benefit of many transmission projects within and outside of the DOM Zone.

4.6.2 TRANSFER CAPABILITIES

It is important to maintain an adequate level of transfer capability to facilitate economic and emergency power flows between neighboring utilities. Transfer capabilities are determined using first contingency (N-1) criteria as defined by NERC. Under N-1 criteria, system improvements are made based on facility loadings and voltages with a critical facility outage in effect. Transfer capabilities are calculated between two or more control areas using N-1 criteria. Maximum transfer capability between control areas may be limited due to overloading of any facility including the interconnections between the control areas. The limiting facility for a particular transfer can vary depending on the source and sink of the transfer. Available Transfer Capabilities ("ATCs") are calculated and posted by PJM for the PJM market. Since the Company is a member of PJM, it no longer explicitly calculates and posts ATCs. ATCs are updated regularly and posted on PJM's website at http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx.

4.6.3 TRANSMISSION INTERCONNECTIONS

For any new generation proposed within the Company's transmission system, either by the Company or by other parties, the generation owner files an interconnection request with PJM. PJM, in conjunction with the Company, conducts Feasibility Studies, System Impact Studies, and Facilities Studies to determine the facilities required to interconnect the generation to the transmission system (Figure 4.6.3.1). These studies ensure deliverability of the generation into the PJM market. The scope of these studies is provided in the applicable sections of the PJM manual 14A[7] and the Company's Facility Connection Requirements document is posted on the Company's website at:
http://www.dom.com/business/electric-transmission/pdf/Facility_Connection_Requirements.pdf.

The results of these studies provide the requesting interconnection customer with an assessment of the feasibility and costs (both interconnection facilities and network upgrades) to

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[7] The PJM manual 14A is posted at http://www.pjm.com/~/media/documents/manuals/m14a.ashx.

interconnect the proposed facilities to the PJM system, which includes the Company's transmission system.

Figure 4.6.3.1 PJM INTERCONNECTION REQUEST PROCESS

Note: Projects May Drop Out of the Queue at any Time

Feas – Feasibility studies
Imp – System Impact Studies
Fac – Facility studies
ISA/CSA – Interconnection Service Agreement / Construction Service Agreement

Source: *Received via e-mail from PJM on March 20, 2008.*

The Company's planning objectives include analyzing planning options for transmission, as part of the IRP process, and providing results that become inputs to the PJM planning processes. In order to accomplish this goal, the Company must comply and coordinate with a variety of regulatory groups that address reliability, grid expansion, and costs which fall under the authority of NERC, PJM, FERC, the SCC, and the NCUC. In evaluating and developing this process, balance among regulations, reliability, and costs are critical to providing service to the Company's customers in all aspects, which includes generation and transmission services.

The Company also evaluates and analyzes transmission options for siting potential generation resources to offer flexibility and additional grid benefits. The Company conducts power flow studies and financial analysis to determine interconnection requirements for new supply-side resources.

The Company uses Promod IV®, which performs security constrained unit commitment and dispatch, to consider the proposed and planned supply-side resources and transmission facilities. Promod IV®, which incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations, is the industry-leading fundamental electric market simulation software.

The Promod IV® model enables the Company to integrate the transmission and generation system planning to: i) analyze the zonal and nodal level Locational Marginal Pricing ("LMP") impact of new resources and transmission facilities, ii) calculate the value of new facilities due to the alleviation of system constraints, and iii) perform transmission congestion analysis.

The model is utilized to determine the most beneficial location for new supply-side resources in order to optimize the future need for both generation and transmission facilities while providing reliable service to all customers. The Promod IV® model evaluates the impact of resources under development that are selected by the Strategist model. Specifically, this Promod IV®

LMP analysis was conducted for the Warren County Power Station, along with the Brunswick County Power Station. In addition, the Promod IV® and Power System Simulator for Engineering were utilized to evaluate the impact of future generation retirements on the reliability of the DOM Zone transmission grid.

Chapter 5

Future Resources

CHAPTER 5 – FUTURE RESOURCES

5.1 FUTURE SUPPLY-SIDE RESOURCES

The Company continues to monitor viable commercial- and utility-scale emerging generation technologies. The Company gathers information about potential and emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including but not limited to planning, financial analysis, construction, operation, alternative energy solutions, and business development. The dispatchable and non-dispatchable resources examined in this 2013 Plan are defined and discussed in the following subsections.

5.1.1 DISPATCHABLE RESOURCES

Biomass

Biomass generation facilities rely on renewable fuel in their thermal generation process. In the Company's service territory, the renewable fuel generally used is waste wood. The Company considers biomass to be carbon neutral from an emissions standpoint. The Company has completed its Altavista biomass conversion and expects to complete major unit modifications to convert the Hopewell and Southampton stations from coal-fired to biomass generation facilities, rated at 51 MW each, by the end of 2013. Greenfield biomass was considered for further analysis in the Company's busbar curve analysis. However, it was found to be uneconomic in comparison to these conversions. Generally, biomass generation facilities are geographically limited by the access to the fuel source.

Circulating Fluidized Bed ("CFB")

CFB combustion technology is a clean coal technology that has been operational for the past few decades and is very flexible in terms of fuel quality. It can consume a wide array of coal types including low British thermal unit ("Btu") waste coal and wood products. The technology uses upward blowing jets of air to suspend the fuel and results in a more complete chemical reaction allowing for efficient removal of many pollutants such as NO_x and SO_2. The preferred location for this technology is within the vicinity of large quantities of waste coal fields. The Company will continue to follow this technology and its associated economics based on the site and fuel resource availability. With the limited site availability and scarcity of fuel resources within the Company's service territory, and strict standards on emissions from the electric generating unit GHG NSPS rule, this resource was not considered for further analysis in the Company's busbar curve analysis.

Coal with Carbon Capture and Sequestration ("CCS")

Coal generating technology is very mature with hundreds of plants in operation across the United States and others under various stages of development. CCS is a technology that collects and traps CO_2 underground. This technology can be combined with many thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal burning facilities. The EPA's electric generating unit GHG NSPS rule requires all new generation resources must meet a strict limit for emissions. To meet these standards, CCS technology is assumed to be required on all new coal and integrated-gasification combined-cycle ("IGCC") facilities. Coal generation with CCS technology, however, is still under development and not currently feasible. The Company will continue to follow this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve analysis.

Coal without CCS

As per the SCC's Final Order in Case No. PUE-2011-00092, the Company included a coal generating facility without CCS for the busbar screening curve. The Company, however, does not believe a new coal generating facility could be built without CCS due to effective and anticipated environmental regulations. This resource was considered for further analysis in the Company's busbar curve analysis.

Energy Storage

There are several different types of energy storage technologies. Energy storage technologies include, but are not limited to, pumped storage hydroelectric power, superconducting magnetic energy storage, capacitors, compressed air energy storage, flywheels, and batteries. Cost considerations have restricted widespread deployment of most of these technologies, with the exception of pumped hydroelectric power and batteries.

The Company is the operator and a 60% owner in the Bath County Pumped Storage Station, which is one of the world's largest pumped storage generation stations, with a net generating capacity of 3,003 MW. Due to their size, pumped storage facilities are best suited for centralized utility-scale applications.

Batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications. Batteries can be used to provide energy for power station blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Recently, batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. Battery storage technology facilitates the dispatchability of these variable energy resources. The primary challenge facing battery systems is the cost. Other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems.

The Company is actively engaged in the evaluation of the potential for energy storage technologies to provide ancillary services, to improve overall grid efficiency, and to enhance distribution system reliability. Due to the costs associated with technologies similar to batteries and location limitations associated with pumped storage facilities, these resources were not considered for further analysis in the Company's busbar curve analysis.

Fuel Cell

Fuel cells are electrochemical cells that convert chemical energy from fuel into electricity and heat. They are similar to batteries in their operation, but where batteries store energy in the components (a closed system), fuel cells consume their reactants. Although fuel cells are considered an alternative energy technology, they would only qualify as renewable in Virginia or North Carolina if powered by a renewable energy resource as defined by the respective state's statutes. The Company will continue to evaluate and monitor developments surrounding fuel cell technology. This resource was considered for further analysis in the Company's busbar curve analysis.

Gas-Fired Combined-Cycle

A natural gas CC plant combines a CT and a steam turbine plant into a single, highly efficient power plant. The option the Company considered for its analysis included the CC 2x1 generators and CC 3x1 generators, with heat recovery steam generators and supplemental firing capability. The CC generators modeled are based on Mitsubishi Heavy Industries GAC and Siemens H units. The difference between the 2x1 and the 3x1 configuration is the addition of another combustion turbine onto the 2x1 configuration. Both the 2x1 and 3x1 resources were considered for further analysis in the Company's busbar curve analysis.

Gas-Fired Combustion Turbine

Gas-fired CT technology has the lowest capital requirements ($/kW) of any resource considered; however, it has relatively high variable costs because of its low efficiency. This is a proven technology with cost information readily available. The CT generators modeled are based on the Siemens 5000F-EE units. This resource was considered for further analysis in the Company's busbar curve analysis.

Geothermal

Geothermal technology uses the heat from the earth to create steam that is subsequently run through a steam turbine. As of 2012, the National Renewable Energy Laboratory has not indicated that there are any viable sites for geothermal technology identified in the eastern portion of the United States.[8] The Company does not view this resource as a feasible option in its service territory at this time; however, it will continue to monitor developments surrounding geothermal technology. This resource was not considered for further analysis in the Company's busbar curve analysis.

Hydro

Facilities powered by falling water have been operating for over a century. Construction of large-scale hydroelectric dams is currently unlikely due to environmental restrictions in our service territory; however, smaller-scale plants, or run-of-river facilities, are feasible in the Company's service territory. Due to the site-specific nature of these plants, the Company does

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[8] Retrieved from: http://www.nrel.gov/geothermal/.

not believe it is appropriate to further investigate this type of plant until a viable site is available. This resource was not considered for further analysis in the Company's busbar curve analysis.

IGCC with CCS[9]

IGCC plants use a gasification system to produce synthetic natural gas from coal in order to fuel a CC. The gasification system process produces a pressurized stream of CO_2 before combustion, which research suggests provides some advantages in preparing the CO_2 for CCS systems. IGCC systems remove a greater proportion of other air effluents in comparison to traditional coal units. The Company will continue to follow this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve analysis.

IGCC without CCS

As per the SCC's Final Order in Case No. PUE-2011-00092, the Company included IGCC without CCS for the busbar screening curve. The Company, however, does not believe a new IGCC unit could be built without CCS due to effective and anticipated environmental regulations. This resource was considered for further analysis in the Company's busbar curve analysis.

Nuclear

With an increasing need for clean, non-carbon emitting baseload power, many electric utilities are re-examining new nuclear power units. The process for constructing a new nuclear unit remains time-consuming with various permits for design, location, and operation required by various government agencies.. For further discussion of the Company's efforts to develop a third unit at the North Anna Power Station, see Section 5.3. This resource was considered for further analysis in the Company's busbar curve analysis.

Nuclear Fusion

The Company will continue to monitor any developments regarding nuclear fusion technology. This resource was not considered for further analysis in the Company's busbar curve analysis.

Small Modular Reactors ("SMR")

SMRs are nuclear units with electrical output of 300 MW or less. SMRs are manufactured almost entirely off site in factories and delivered and installed on site in modules. The small power output of SMRs means electricity costs more per MW than a larger reactor, but the initial costs of building the plant are significantly reduced. An SMR provides more security through underground placement of reactors and spent-fuel storage pools, a natural cooling feature that can continue to function in the absence of external power, as well as more efficient containment and lessened proliferation concerns. SMRs are still in the early stages of development and permitting, and thus at this time are not considered a viable resource for the Company. More in depth research and development is currently taking place regarding SMR technology that the

[9] The Company currently assumes that the captured carbon cannot be sold.

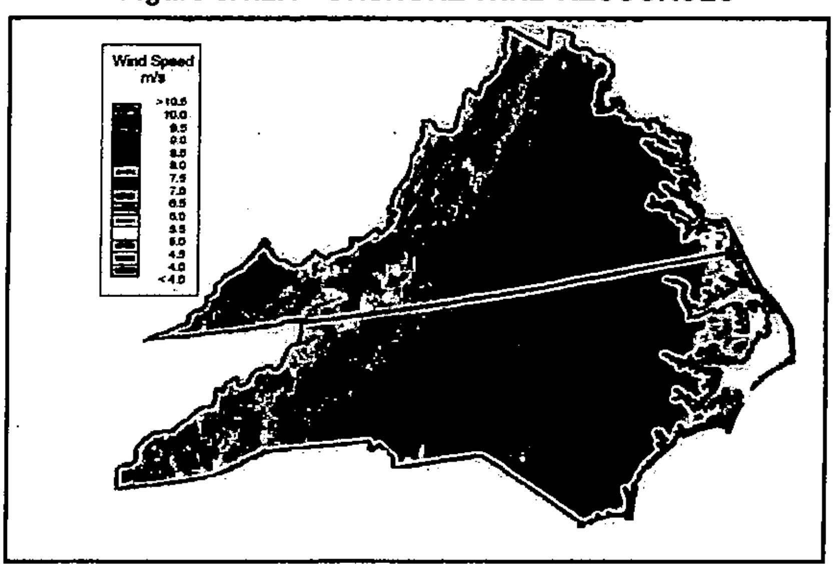
Company will continue to monitor. This resource was not considered for further analysis in the Company's busbar curve analysis.

5.1.2 NON-DISPATCHABLE RESOURCES

Onshore Wind

Wind resources are one of the fastest growing resources in the United States. The Company has considered onshore wind resources as a means of meeting the RPS goals, REPS requirements, and as a cost-effective stand-alone resource. The suitability of this resource is highly dependent on locating an operating site that can achieve an acceptable capacity factor. Additionally, these facilities tend to operate at times that are non-coincidental with peak system conditions and therefore generally achieve a capacity contribution significantly lower than their nameplate ratings. The Company understands that there is limited land available in its service territory with sufficient wind characteristics. Figure 5.1.2.1 displays the onshore wind potential of Virginia and North Carolina. It is important to note that the Eastern portions of the United States wind resources are limited and available only in specialized locations, such as on mountain ridges. The Company continues to examine onshore wind; however, there is a limited amount of onshore wind available within or near the Company's service territory. The Company has identified three feasible sites for consideration as onshore wind facilities in the western part of Virginia on mountaintop locations. This resource was considered for further analysis in the Company's busbar curve analysis.

Figure 5.1.2.1 ONSHORE WIND RESOURCES



Source: *Retrieved from the National Renewable Energy Laboratory on June 21, 2011; see http://www.windpoweringamerica.gov/pdfs/wind_maps/us_windmap_80meters.pdf.*

Offshore Wind

Offshore wind has the potential to provide the largest, scalable renewable resource for Virginia with near-term resource availability of up to 2,000 MW (nameplate) as seen in Figure 5.1.2.2. Virginia has a unique offshore wind opportunity due to its shallow continental shelf extending approximately 40 miles off the coast, proximity to load centers, availability of local supply chain infrastructure, and world class port facilities. However, one challenge facing offshore wind development is its complex and costly installation and maintenance when compared to onshore wind. This resource was considered for further analysis in the Company's busbar curve analysis.

Figure 5.1.2.2 OFFSHORE WIND RESOURCES

Source: *Retrieved from the U.S. Department of Energy on June 21, 2011; see http://www.windpoweringamerica.gov/windmaps/offshore.asp.*

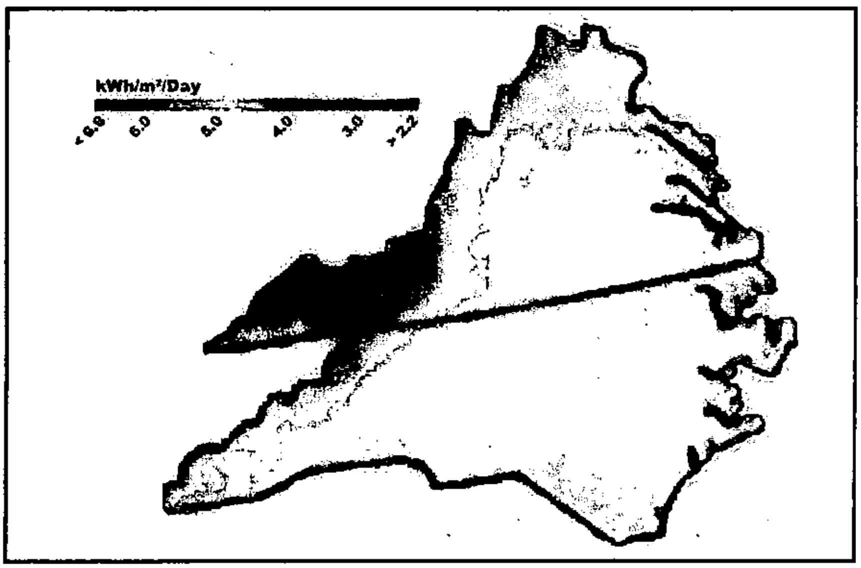
Solar PV & Concentrating Solar Power ("CSP")

Solar PV and CSP are the two main types of solar technology used in electric power generation. Solar PV systems consist of interconnected PV cells that use semiconductor devices to convert sunlight into electricity. Solar PV technology is found in both large-scale and distributed systems and can be implemented where unobstructed access to sunlight is available. CSP systems utilize mirrors to reflect and concentrate sunlight onto receivers to convert solar energy into thermal energy that in turn produces electricity. CSP systems are generally used in large scale solar plants and are mostly found in the southwestern area of the country where solar resource potential is the highest.

Although solar PV costs have declined in recent years, installed system costs can vary widely depending on system size, technology types, and site specific factors. For example, a solar cell's output and efficiency depends on various components, such as its design and materials, the intensity of the solar radiation hitting the cell, and the cell's temperature. Due to its variable nature as a generating resource, solar PV generation is not dispatchable and contributes less to peak load and reserve requirements than conventional generation resources. However, continuing advancements in storage technology may allow solar output to become a more reliable resource in the future. Figure 5.1.2.3 displays the solar PV potential of Virginia and North Carolina.

Solar PV technology was considered for further analysis in the Company's busbar curve analysis, while CSP was not. Also included in the Company's busbar curve analysis is a solar PV unit at a brownfield (existing generation) site (solar tag). By installing solar at an existing generating facility, the output can be tied into the existing electrical infrastructure. Use of such a site would allow the Company to decrease the initial fixed cost of the resource, while the other characteristics of the unit stay the same.

Figure 5.1.2.3 SOLAR PV RESOURCES



Source: *Retrieved from the National Renewable Energy Laboratory on July 19, 2010; see http://www.nrel.gov/gis/images/map_pv_national_lo-res.jpg.*

Tidal & Wave Power

Tidal and wave power rely on ocean water fluctuations to collect and release energy. Significant research is being conducted by many individuals and firms into the development of tidal- and wave-powered electric facilities. However, neither type of facility has proven to be commercially available. The Company will continue to monitor developments surrounding these technologies. This resource was not considered for further analysis in the Company's busbar curve analysis.

5.1.3 ASSESSMENT OF ALTERNATIVE SUPPLY-SIDE RESOURCES

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or power pool. The technology's ability to be dispatched is based on whether the resource was able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand requirements. Further, this portion of the analysis requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel, operation and maintenance. Figure 5.1.3.1 summarizes the resource types that the Company reviewed as part of the 2013 IRP. Those resources considered for further analysis in the busbar screening model are identified in the final column.

Figure 5.1.3.1 ALTERNATIVE SUPPLY-SIDE RESOURCES

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource
Battery/Pumped Storage	Intermediate	Yes	Varies	No
Biomass	Baseload	Yes	Renewable	Yes
CC 2x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 3x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CFB	Baseload	Yes	Coal	No
Coal w/ CCS	Intermediate	Yes	Coal	Yes
Coal w/o CCS	Baseload	Yes	Coal	Yes
CT	Peak	Yes	Natural Gas	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes
Geothermal	Baseload	Yes	Renewable	No
Hydro Power	Intermittent	No	Renewable	No
IGCC CCS	Intermediate	Yes	Coal	Yes
IGCC w/o CCS	Baseload	Yes	Coal	Yes
Nuclear	Baseload	Yes	Uranium	Yes
Offshore Wind	Intermittent	No	Renewable	Yes
Onshore Wind	Intermittent	No	Renewable	Yes
Solar PV	Intermittent	No	Renewable	Yes
Solar Tag	Intermittent	No	Renewable	Yes
Tidal & Wave Power	Intermittent	No	Renewable	No

The resources not included as busbar resources for further analysis contained barriers such as the feasibility of the resource in the Company's service territory, the stage of technology development, and the availability of reasonable cost information.[10] Although these resources were not considered in this 2013 Plan, the Company will continue researching all utility-scale technologies. The Company is committed to using technologies at reasonable and prudent costs that best meet the energy needs of customers.

[10] Please see www.epri.com for more information on confidence ratings.

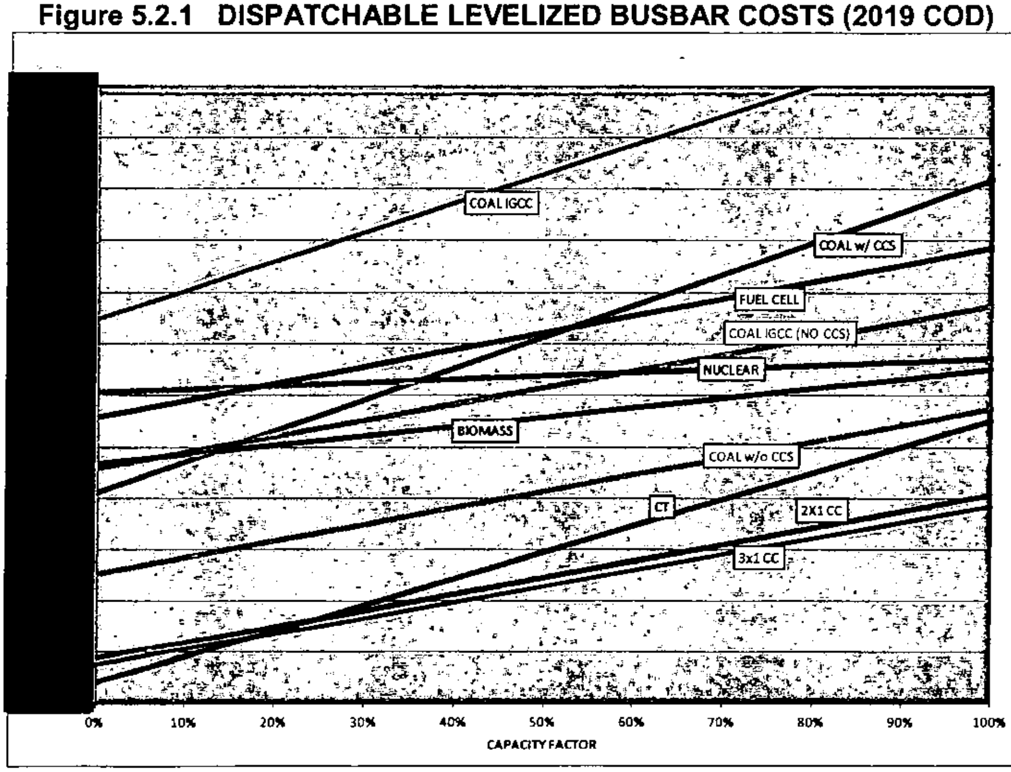
5.2 LEVELIZED BUSBAR COSTS

The Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed operation and maintenance ("O&M") costs, expected service life, and overnight construction costs.

Extraordinarily Sensitive Figures 5.2.1 and 5.2.2 display summary results of the busbar model comparing the economics of the different technologies discussed in Sections 5.1.1 and 5.1.2. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources.

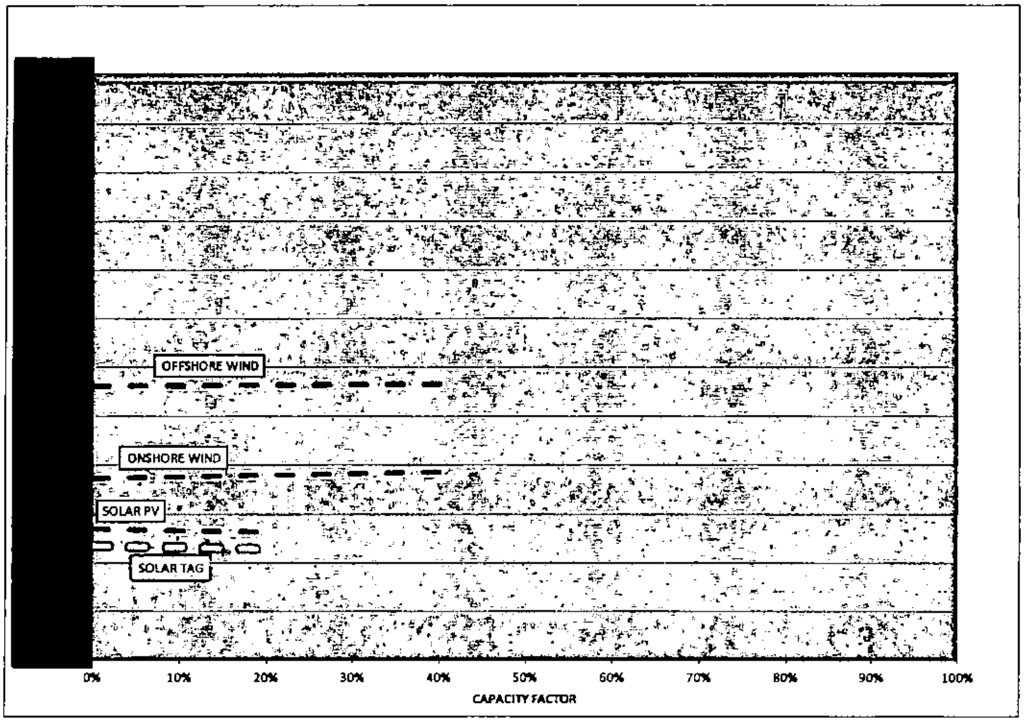
*****EXTRAORDINARILY SENSITIVE INFORMATION REDACTED*****

Figure 5.2.1 DISPATCHABLE LEVELIZED BUSBAR COSTS (2019 COD)



EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

Figure 5.2.2 NON-DISPATCHABLE LEVELIZED BUSBAR COSTS (2019 COD)



Extraordinarily Sensitive Appendix 5A contains the tabular results of the screening level analysis. Confidential and Extraordinarily Sensitive Appendix 5B displays the heat rates, fixed and variable operations expenses, maintenance expenses, expected service lives, estimated 2013 real dollar construction costs, and the first year economic carrying charge.

In Extraordinarily Sensitive Figure 5.2.1, the lower portion of the combined curves represents the lowest cost of all units at an associated operating capacity factor range between 0% and 100%. Resources that lie above the combined curves generally fail to move forward in the resource optimization. Extraordinarily Sensitive Figures 5.2.1 and 5.2.2 allow comparative evaluation of resource types. The Y axis depicts the amount of invested total fixed cost of the unit at 0% capacity factor. Depicted along the X axis, as capacity factors increase, the slope of the unit equals the fuel, emissions, and total variable costs, along with any REC or Production Tax Credit ("PTC") value a given unit may receive.

Extraordinarily Sensitive Figure 5.2.1 shows that CT technology is currently the most cost-effective option at capacity factors less than 20% for meeting Company's peaking requirements. The comparison of CC 3x1 and CC 2x1 technology indicates that the CC 3x1 technology is more economic. Currently, the CC 3x1 technology is the most economical option for capacity factors greater than 20% and, therefore, is an economical way for the Company to meet its energy requirements.

Nuclear units have higher total life-cycle costs than a CC 3x1; however, they operate historically at higher capacity factors and have relatively more stable fuel costs. Nuclear power provides fuel diversity and enhances price stability and reliability. New coal generation facilities without CCS technology will not meet the emission limitation included in the electric generating unit NSPS for new sources of greenhouse gases.

A direct comparison between dispatchable and non-dispatchable resources on the same busbar curve is not appropriate due to the intermittent production, the limited dispatchability, and the lower dependable capacity ratings associated with non-dispatchable resources. Wind and solar plants produce less energy at peak demand periods, therefore more capacity would be required to maintain the same level of reliability. For example, onshore wind provides only 13% of its nameplate capacity as firm capacity that is available to meet the Company's PJM resource requirements as described in Chapter 4. Extraordinarily Sensitive Figure 5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Based on this analysis, the economic order for these non-dispatchable resources is: solar tag, solar PV, onshore wind, and offshore wind. The Company is routinely updating and evaluating the costs and availability of renewable resources, as discussed in Section 5.4. See Figure 5.2.3 for a summary and explanation of non-dispatchable renewable resource nameplate and firm capacities considered in the busbar analysis.

Figure 5.2.3 RENEWABLE CAPACITY SUMMARY

Resource Type	Nameplate	Firm Capacity
Onshore Wind	247	32
Offshore Wind	1,600	267
Offshore Wind Demonstration Project	12	2
Solar PV	200	77
Solar Tag	20	8
Solar Partnership Program	24[1]	7

***Note:* 1)** *Solar Partnership Program DC capacity is 30 MW (nameplate) while the figure displays AC capacity.*

The assessment of alternative resource types and the busbar screening process provided a useful foundation in selecting resources for further analysis. However, the busbar curve is static in nature because it relies on an average of all of the cost data of a resource over its lifetime. Further analysis was conducted in Strategist to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matched the resources found to be cost-effective in this screening process. This simulation analysis resulted in selecting the type and timing of additional resources that economically fit the Company's current and future needs.

5.3 GENERATION UNDER DEVELOPMENT

North Anna 3

The Company is in the process of developing a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia, subject to receiving all required approvals.[11] The 2013 Plan has North Anna 3 achieving commercial operation in October 2024, with capacity being available to meet the summer peak in 2025. This is the earliest possible in-service date given permitting and construction lead times. The Company has not committed to build North Anna 3 to date but continues to develop the project to assure that this supply-side resource option remains available to its customers.

The Company has revised its technology selection for North Anna 3 to GEH's ESBWR nuclear technology rather than the Mitsubishi Heavy Industries Advanced Pressurized Water Reactor identified in the 2012 Plan. This decision was based on a continuation of the competitive procurement process that began in 2009 to find the best solution to meet its need for future baseload generation. Since 2009, GEH has continued to refine its design and has made significant progress toward obtaining federal approval. In addition, GEH and its consortium partner Fluor Enterprises, Inc. ("Fluor") provided contract enhancements that are expected to benefit customers and stakeholders over the new unit's planned 60-year life. In July 2013, the Company submitted a revised COL application to the NRC to reflect the change in technology.

The Company expects to receive the COL no earlier than late 2015 and intends to maintain the development option of North Anna 3 for several key reasons. Those reasons are as follows:

a. North Anna 3 will provide much needed baseload capacity to the region in the latter portion of the Planning Period while enhancing system reliability;
b. nuclear units are near emission-free generation;
c. North Anna 3 will enhance fuel diversity within the Company's generation portfolio, which will in turn, promote fuel price stability for customers; and
d. nuclear power is the lowest cost large-scale dispatchable baseload generating alternative to natural gas; see Figure 5.2.1.

Future Combined-Cycle

The Company is currently in the early stage of development of a natural gas fueled combined-cycle facility. The current forecasted COD is 2019.

Onshore Wind

The Company continues to pursue onshore wind development; however, there is a limited amount of onshore wind available within or near the Company's service territory. Only three feasible sites have been identified by the Company for consideration of onshore wind facilities. These sites are located in the western part of Virginia on mountaintop locations.

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[11] Originally, Old Dominion Electric Cooperative ("ODEC"), part owner of North Anna Units 1 and 2, was also a participant in the development of North Anna 3 but informed the Company of its intent to no longer participate in February 2011. On January 30, 2013, the NRC approved the transfer of ODEC's interest to the Company.

Offshore Wind

In December 2012, a Company-led team was among seven projects selected by the DOE for a $4 million award for initial engineering, design, and permitting for an offshore wind turbine demonstration facility off the coast of Virginia. The DOE will select up to three projects for follow-on phases that focus on detailed design, construction, installation, and data collection. The final three projects selected could receive up to $47 million each in federal funding over four years, with a goal to have the projects in operation by the end of 2017. In its DOE application, the Company has proposed designing, developing, and demonstrating a grid-connected, 12 MW offshore wind facility (the Offshore Wind Demonstration Project) consisting of two Alstom 6 MW turbines mounted on innovative foundations. In addition to the Company, several partners are collaborating on the project, including Alstom; National Renewable Energy Laboratory; the Commonwealth of Virginia Department of Mines, Minerals and Energy; Virginia Tech, representing the Virginia Coastal Energy Research Consortium; KBR, a global engineering, construction and services firm with experience in offshore wind; and Newport News Shipbuilding, a division of Huntington Ingalls Industries.

Solar PV

Pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly (House Bill 1686), the Company announced plans in late 2011 for a solar DG demonstration program with two components: (1) the Solar Partnership Program for up to 30 MW (DC) of Company-owned solar DG; and (2) the Solar Purchase Program, a tariff allowing the Company to purchase up to 3 MW of energy output from customer-owned solar DG. Both components were approved by the SCC as detailed below.

Solar Purchase Program

On March 22, 2013, the SCC approved the Company's Solar Purchase Program to purchase energy from qualifying residential and non-residential solar customer-generators at a fixed price of 15 cents per kWh under Rate Schedule SP, a voluntary experimental rate, for a period of five years.

Rate Schedule SP is designed to facilitate installation of up to 3 MW of customer-owned solar DG (up to 1.8 MW residential and up to 1.2 MW non-residential) as an alternative to net energy metering by allowing the Company to purchase 100% of the energy output, including all environmental attributes and associated RECs, from qualifying solar customer-generators. The 15 cents per kWh price paid under Rate Schedule SP includes an avoided energy cost component and a voluntary environmental contribution component provided by those customers participating in the Company's Green Power® program.

Figure 5.3.1 GENERATION UNDER DEVELOPMENT[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Capacity (Net MW)	
						Summer	Winter
2017	Solar	VA	Renewable	Intermittent	40	15	15
2017	Solar Tag	VA	Renewable	Intermittent	10	4	4
2018	Solar	VA	Renewable	Intermittent	40	15	15
2018	Offshore Wind Demonstration Project	VA	Wind	Intermitent	12	2	2
2019	Combined Cycle	VA	Natural Gas	Intermediate/Baseload	1,509	1,375	1,509
2019	Solar	VA	Renewable	Intermittent	40	15	15
2020	Solar	VA	Renewable	Intermittent	40	15	15
2020	Solar Tag	VA	Renewable	Intermittent	10	4	4
2021	Solar	VA	Renewable	Intermittent	40	15	15
2022	Wind 1	VA	Renewable	Intermittent	120	16	16
2023	Wind 2	VA	Renewable	Intermittent	81	10	10
2024	Wind 3	VA	Renewable	Intermittent	46	6	6
2025	North Anna 3	Mineral, VA	Nuclear	Baseload	1,514	1,453	1,514

Notes: 1) All Generation Under Development projects and capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals.

Appendix 5C provides the in-service dates and capacities for generation resources under development.

5.4 ALTERNATIVE AND RENEWABLE ENERGY RESOURCES & TECHNOLOGIES

The Company conducts technology research in the renewable and alternative energy technologies sector, participates in Federal and state policy development on alternative energy initiatives, and identifies potential alternative energy resource and technology opportunities within the existing regulatory framework for the Company's service territory. The Company is actively pursuing the following technologies and opportunities.

<u>Research and Development Initiatives - Virginia</u>

A 2012 revision to Va. Code § 56-585.2 resulting from HB 1102 and SB 413, legislation passed by the 2012 General Assembly at the request of the Governor, allows utilities that are participating in Virginia's RPS program to meet up to 20% of their annual RPS Goals using RECs issued by the SCC for investments in renewable and alternative energy research and development activities. Pursuant to § 56-585.2, the Company is currently partnering with 11 institutions of higher education on Virginia renewable and alternative energy research and development projects. The Company intends to file its first annual report by March 31, 2014, analyzing the prior year's PJM REC prices and quantifying its qualified investments to facilitate the SCC's validation and issuance of RECs for Virginia renewable and alternative energy research and development projects.

Research and Development Initiatives – North Carolina

NCGS § 62-133.8.h allows utilities to recover up to $1,000,000 per year through a REPS rider for research that encourages the development of renewable energy, energy efficiency, or improved air quality. Pursuant to this law, the Company plans to develop a microgrid project at its Kitty Hawk District Office in North Carolina. Plans for the microgrid project include innovative distributed renewable generation and energy storage technologies. A microgrid, as defined by the DOE, is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid, allowing it to operate in grid-connected or island-mode. The project, as currently planned, would include four different types of micro-wind turbines, a solar PV array, and a lithium-ion battery that would be integrated behind-the-meter with the existing on-site diesel generator and utility feed. The Company plans to commence construction in late 2013 and to complete the microgrid project in mid-year 2014.

Rate Schedule RG

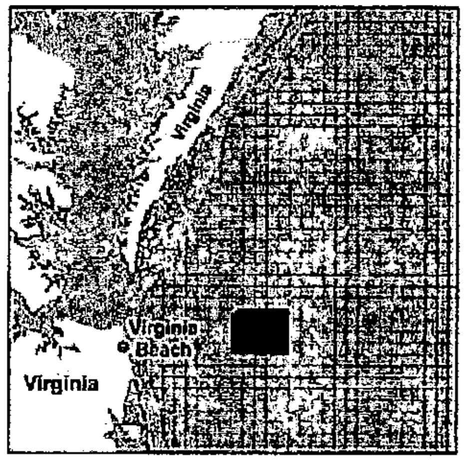
In response to customer requests and to further promote the development of renewable energy, the Company filed an application with the Virginia SCC on December 20, 2012 to establish a Renewable Generation Pilot Program ("RG Pilot Program") whereby large non-residential customers in Virginia would have the ability to meet a portion of their energy requirements with renewable energy. As proposed, the Program would only be available as a voluntary companion rate to non-residential customers (1) with demands greater than 500 kW that are served under Rate Schedule GS-3 or GS-4; and (2) with individual account purchases between 1,000,000 kWh and 24,000,000 kWh annually. The purchase price under Rate Schedule RG will represent energy and its associated renewable attributes only, with each participating customer continuing to purchase capacity and the remaining portion of its energy needs under Rate Schedule GS-3 or GS-4. Schedule RG would be available to eligible customers for an enrollment period of three years or until the Program cap of 240,000,000 kWh or 100 customers is met. Under the Program, the renewable energy resource may be located outside of the Company's service territory, but it must be within the geographic scope of the PJM wholesale market. If approved, the Company plans to implement the Program within 90 days from the date approval is granted. More information regarding the RG Pilot Program can be found on the VA SCC website under Docket No. PUE-2012-00142.

Offshore Wind

The Company is actively participating in offshore wind policy and technology development in order to identify ways to advance offshore wind responsibly and cost-effectively for the benefit of its regulated electric customers in Virginia and North Carolina.

The Company responded to the BOEM's Call for Information and Nominations (Call) in Virginia in March 2012. Subsequently, the BOEM released a proposed sale notice for the Virginia Wind Energy Area ("WEA") in December 2012 (Figure 5.4.1) and a final sale notice in July 2013. BOEM has scheduled an auction for September 4, 2013, and the Company is planning to participate. Seven other developers have also been qualified to participate in the auction. BOEM will competitively auction the entire WEA as a single development block, which consists of 112,800 acres approximately 24 miles off the coast of Virginia Beach, Virginia. Initial estimates indicate that the area could accommodate between 1,500 and 2,000 MW of offshore wind capacity.

Figure 5.4.1 VIRGINIA WIND ENERGY AREA



The Company also submitted a response to the Call in North Carolina in February 2013, and is evaluating the potential for a project off the coast of that state.

Offshore wind has the potential to provide the largest source of renewable generation for Virginia; however, offshore wind is significantly more expensive compared to other renewable generation alternatives as seen in Figure 5.2.2. The Company is actively working to evaluate ways to reduce the cost of offshore wind energy through two DOE funding awards. The DOE awarded the Company and its partners a $500,000 grant in 2011 to identify the impact of innovative technologies on reducing the levelized cost of offshore wind energy relative to a baseline. The grant team brings together the expertise of several partners, including the Company, a wind turbine manufacturer (Alstom), a federally funded research and development center (National Renewable Energy Laboratory), a maritime planning and engineering firm (Moffatt & Nichol), and a state university (Virginia Polytechnic Institute and State University). This grant project is currently underway and is scheduled to be complete in 2014.

Demonstrating its support for offshore wind off the coast of Virginia, the 2011 General Assembly established a goal of developing 3,000 MW (nameplate) of offshore wind by 2025. Furthermore, the Virginia General Assembly passed legislation in 2010 that created the Virginia Offshore Wind Development Authority ("VOWDA") to help facilitate offshore wind energy development. The Company is represented on the executive committee of VOWDA by an appointee of the Governor of Virginia. As required by the 2010 legislation, the Company completed a transmission study to determine possible offshore wind interconnection points to the onshore transmission grid. The Company released the results of the study in December 2010, which found that Virginia has an advantage compared to many states because it has the capability to interconnect large scale wind generation facilities with the existing grid in Virginia Beach, Virginia. The study revealed that up to 4,500 MW (nameplate) of offshore wind generation can be connected with minimal onshore transmission upgrades. The Company completed a second study in 2012, evaluating offshore transmission options to potentially support multiple projects. The study found that for every 500 - 700 MW (nameplate) of offshore wind capacity constructed, one service platform is appropriate with two lines to shore. This transmission solution limits the potential for stranded transmission investment and emphasizes the potential cost savings that may be achieved through a phased build-out, with a potential for standardization of offshore transmission infrastructure.

The Company is also a member of the Virginia Offshore Wind Coalition ("VOW"). The VOW is an organization comprised of developers, manufacturers, utilities, municipalities, businesses, and other parties interested in offshore wind. This group advocates on the behalf of offshore wind development before the Virginia General Assembly and with the Virginia delegation to Congress.

EV Initiatives

Various automotive original equipment manufacturers ("OEMs") have released EVs for sale to the public in the Company's service territory. The Chevrolet Volt, General Motor's first plug-in hybrid electric vehicle ("PHEV"), and the Nissan Leaf, an all-electric vehicle, became available for sale in the Company's Virginia service territory in 2011. Since that time, the Company has monitored the introduction of EV models from several other OEMs in its Virginia service territory. These include, but are not limited to, the Toyota Prius Plug-in, the Ford Focus Electric and C-Max Energi, the Tesla Roadster and Model S, the Honda FIT, and the Mitsubishi i-MIEV. While the overall penetration of EVs has been somewhat lower than anticipated, recent registration data from the Virginia Department of Motor Vehicles demonstrates significant growth during last year. Sales of EVs and PHEVs have initially followed the historical adoption patterns of hybrid vehicles, and the Company expects this trend to continue. In the 2013 Plan, the Company used data from the Virginia Department of Motor Vehicles, Electric Power Research Institute ("EPRI") and Polk Automotive to develop a projection of system level EV and PHEV penetrations across its service territory.

The Company developed load shapes to evaluate potential capacity and energy impacts of EVs and PHEVs on its system. The Company projects approximately 215,728 EVs and PHEVs will be on the road in 2028, which would equate to approximately 119 MW of additional potential load and an additional annual energy usage of 641 GWh from EV charging. To encourage customers to charge EVs during off-peak hours to avoid potentially adverse grid impacts, the Company launched an EV Pilot Program in Virginia in October 2011 offering experimental and voluntary EV rate options to encourage customers to charge their EVs during off-peak periods. These rate options are further discussed in Section 3.2.3.

5.5 FUTURE DSM INITIATIVES

The Company is committed to offering cost-effective DSM programs in its Virginia and North Carolina service territories in order to meet customers' needs and improve the environment. The Company has developed relationships with third-party vendors to assist in evaluating and implementing programs approved by the Commission(s).

The Company initiated its SRP in 2010. Suggestions received during this process were included in developing the proposed and future DSM initiatives included in this 2013 Plan. The Company plans to hold its next SRP in the fall of 2013.

When potential programs are identified as possible DSM resources, the Company's analysis of future DSM programs begins with a screening process that determines whether a DSM program warrants further evaluation. If a DSM program passes the initial screening, ICF provides the Company with program and modeling assumptions for that program. Next, the programs are evaluated using the Strategist model with respect to the four cost/benefit tests discussed in Appendix 5D. While these cost/benefit tests are a key component of the Company's analysis, it also considers stakeholder impacts, the potential for achieving a high level of acceptance by customers, and the potential for energy and demand reductions. The Company modeled the demand-side resources over the Study Period, including input variables from many sources. These projections were based on the best available information, including industry data acquired from ICF, which validated the DSM program design parameters. Appendix 5E provides the estimated annual energy savings for all DSM programs included in the 2013 Plan.

The Company has developed four incremental phases of DSM programs since 2008 and will continue to work with consultants to develop and evaluate any additional programs for the Virginia and North Carolina service territories that meet the Company's cost/benefit test criteria. The Company also has KEMA under contract to provide EM&V analysis for all of the Company's approved programs. Data gathered from the EM&V activity is used to update capacity and energy impacts, projected customer penetration levels for the DSM programs, and adjust market potential in the future. The Company works closely with ICF and KEMA on a regular basis to update existing program designs and modeling assumptions.

In order to identify more DSM programs, it has been suggested in formal proceedings and by parties to the SRP, that the Company should perform a DSM market potential study. The Company has initiated a DSM Market Potential Study to identify additional programs for the 2014 Plan. This study would take into account the many parameters that have changed since the SCC's 2009 DSM proceeding (Case No. PUE-2009-00023) and also factor in the current requirements for cost/benefit screening. This will give the Company, its customers, stakeholders, the SCC and the NCUC an updated view of the amount of DSM that could realistically be achieved in the Company's Virginia and North Carolina service territories under the current laws and regulations. The Company plans to hold its next SRP meeting in the fall of 2013.

5.5.1 STANDARD DSM TESTS

To evaluate DSM programs, the Company utilized four of the five standard tests from the California Standards Practice Manual. Based on the SCC and the NCUC findings and rulings in the Company's Virginia DSM proceedings (Case Nos. PUE-2009-00023, PUE-2009-00081, PUE-2011-00093, and PUE-2012-00100) and 2010 North Carolina DSM proceedings (Docket No. E-22 Subs 463, 465, 466, 467, 468, and 469), the Company's future DSM programs are evaluated on both an individual and portfolio basis.

In the 2011 and 2012 Plans, the Company used the following criteria when evaluating DSM programs for inclusion in the Plan. First, the Company reviewed a program's individual Ratepayer Impact Measure ("RIM") test score. If a program's RIM score was above 1.0, and the other individual test scores were also above 1.0, then the program was included in the portfolio of DSM programs and was submitted for approval. If a program's individual RIM score was below 1.0, and the Utility Cost ("UCT") and Participant test scores were above 1.0, then the Company looked for a significantly high Total Resource Cost ("TRC") score before suggesting that the program be pursued. For the 2011 and 2012 Plans, the Company used a target TRC score of 2.0 or greater as a guideline for program acceptance.

For the 2013 Plan, the Company made changes to its DSM screening criteria in recognition of the General Assembly's guidance through the 2012 Legislation that a program "shall not be rejected based solely on the results of a single test," for purposes of this filing, the Company has adjusted the requirement that the TRC score be 2.0 or better when the RIM test is below 1.0 and the Utility Cost and Participant tests have passing scores. The Company will now consider including DSM programs that have passing scores (cost/benefit scores above 1) on the Participant, Utility and TRC tests. This change will allow the Company to accomplish two objectives. It will allow the Company to propose additional DSM programs, ones that may fail the RIM test but have passing scores on the other three tests. If the new programs are approved by the SCC, it will allow the Company to help the Commonwealth meet its 10% energy reduction target by 2022. Also, by giving the UCT more weight, the Company will be able to propose, and if approved, have programs which help the Company reduce its overall future revenue requirement, which will benefit all customers.

Although the Company uses these criteria to assess DSM programs, there are circumstances that require the Company to deviate from the aforementioned criteria and evaluate certain programs which do not meet these criteria on an individual basis. These DSM Programs serve important policy and public interest goals, such as that recognized by the SCC in approving the Low Income Program as part in SCC Case No. PUE-2009-00081 and in NCUC Docket No. E-22, Sub 463.

5.5.2 FUTURE DSM PROGRAMS

As part of the IRP process, the Company evaluated possible future DSM programs in Virginia and North Carolina, referred to herein as "future programs." These programs have met the Company's evaluation criteria for inclusion in the 2013 Plan as described in Section 5.5.1. Appendix F includes a brief description of each potential future DSM program. Appendices 5G, 5H, 5I, and 5J provide the non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations, respectively, for each future program. Currently, the Company plans for programs to be proposed in North Carolina after approval in Virginia.

5.5.3 FUTURE DSM PROGRAMS' COST-EFFECTIVENESS RESULTS

The Company performs individual cost/benefit tests on each future DSM program. These results were used to determine if a program should be included as a future DSM program in this 2013 Plan. The Company believes this evaluation is consistent with the guidance provided by the SCC and the NCUC and legislation and regulations in both states. Figure 5.5.3.1 provides the future DSM programs' individual cost/benefit results and projected cumulative demand and energy reductions by 2028.

Figure 5.5.3.1 FUTURE DSM INDIVIDUAL COST-EFFECTIVENESS RESULTS

Program	Participant	Utility	TRC	RIM	2028 MW Reduction	2028 GWh Reduction
Voltage Conservation Program	N/A	2.35	2.35	0.47	0	2,037
Non-Residential Re-Commissioning Program	3.40	0.97	0.98	0.38	0	1
Non-Residential Custom Incentive Program	2.07	1.07	0.85	0.45	74	292
New Residential Low Income Program	1.37	0.13	0.14	0.10	3	20

The Company also performed a portfolio evaluation to ensure that each DSM program passed the cost/benefit tests as a portfolio of programs. It is important to consider the portfolio results since all resources available to meet or reduce load are considered together. It is also important to examine the portfolio run, which includes incremental common costs. Common costs are expenses that cannot be directly tied to any individual program but are incurred based on program start-up and general implementation costs for the collective DSM Program offerings. The common costs are included in the portfolio run to ensure the addition of these expenses does not alter the overall cost-effectiveness of the portfolio.

Figure 5.5.3.2 provides the future DSM portfolio's cost/benefit results and projected demand and energy reductions.

Figure 5.5.3.2 FUTURE DSM PORTFOLIO COST-EFFECTIVENESS RESULTS

Program	Participant	Utility	TRC	RIM	2028 MW Reduction	2028 GWh Reduction
Voltage Conservation Program	N/A	2.35	2.35	0.47	0	2,037
Non-Residential Re-Commissioning Program	3.40	0.97	0.97	0.38	0	1
Non-Residential Custom Incentive Program	2.07	1.07	0.85	0.45	74	294
New Residential Low Income Program	1.37	0.12	0.14	0.10	3	20
Portfolio Results	9.71	1.72	1.65	0.45	77	2,353

5.5.4 REJECTED DSM PROGRAMS

The Company has evaluated a wide variety of DSM programs for both the residential and non-residential sectors. During the planning process, the Company internally rejects programs that do not meet the Company's planning criteria. Rejected programs may be re-evaluated for inclusion in future DSM portfolios, if there are changes in program or resource planning assumptions that indicate those programs may meet then current DSM selection criteria.

A list of IRP rejected programs from prior IRP cycles is shown in Figure 5.5.4.1.

Figure 5.5.4.1 IRP REJECTED DSM PROGRAMS

Program
Commercial HVAC Tune-Up Program
Curtailment Service Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
Programmable Thermostat Program
Residential Heat Pump-Tune Up Program
Residential Refrigerator Turn-In Program
Residential Solar Water Heating Program
Residential Water Heater Cycling Program
Residential Comprehensive Energy Audit Program
Residential Radiant Barrier Program
Residential Lighting (Phase II) Program
Commercial Refrigeration Program

5.5.5 REJECTED DSM PROGRAMS' COST-EFFECTIVENESS RESULTS

No additional DSM Programs have been rejected as part of the Company's 2013 Plan.

5.5.6 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be through methods that raise program awareness and attention such as mass marketing and targeted advertising in Virginia and North Carolina.

5.5.7 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.5.7.1 represents approximately 3,149 GWh in energy savings from the DSM programs at a system-level by 2028.

Figure 5.5.7.1 DSM ENERGY REDUCTIONS

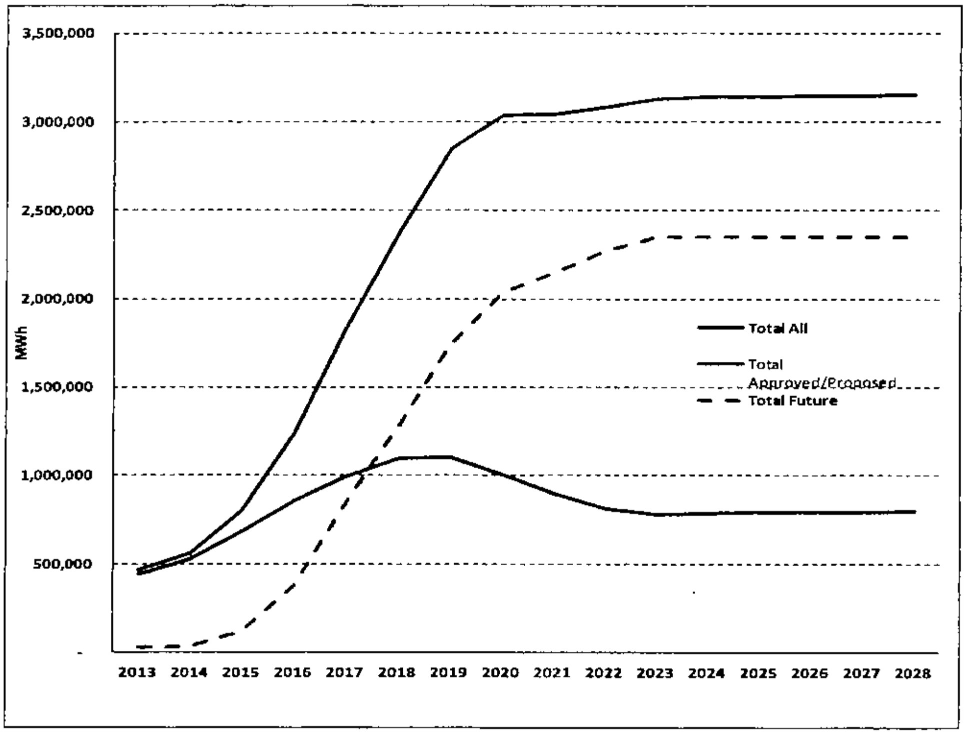
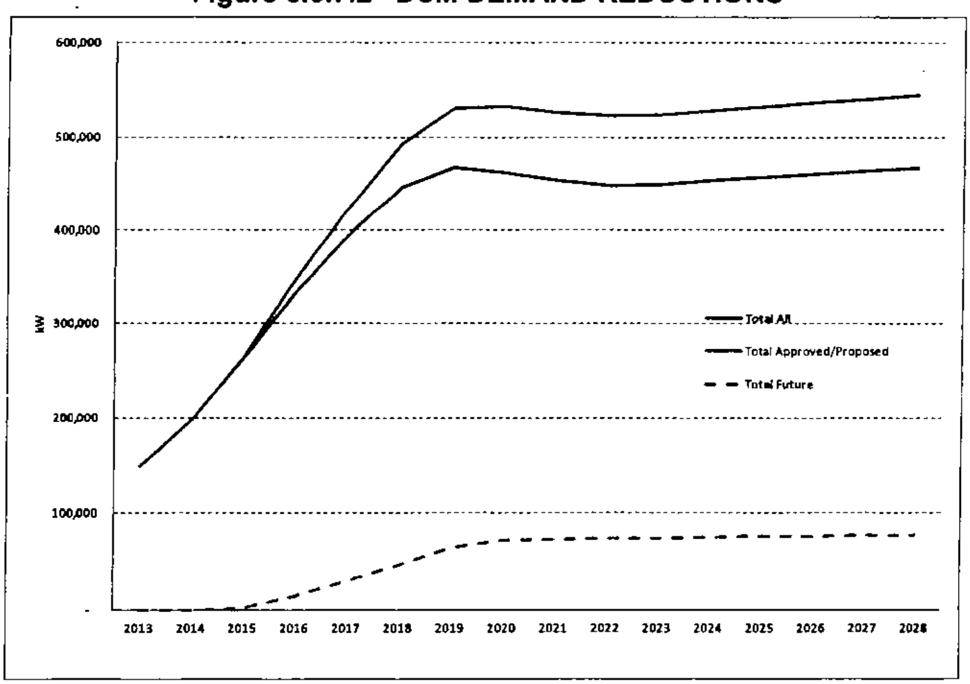


Figure 5.5.7.2 represents a system coincidental demand reduction of approximately 544 MW by 2028 from the DSM programs at a system-level.

Figure 5.5.7.2 DSM DEMAND REDUCTIONS



The capacity reductions for the portfolio of DSM programs are lower than the projections in the 2012 Plan. The total capacity reduction by the end of the planning period was 821 MW for the portfolio of DSM programs in the 2012 Plan and is 544 MW in the 2013 Plan. This represents approximately a 34% decrease in demand reductions. The largest decrease in peak reductions in this Plan was the Air Conditioner Cycling Program, which had a 55% reduction in peak contribution primarily due to a reduction in projected program penetrations. The energy reduction for the DSM programs was 3,400 GWh in the 2012 Plan and is approximately 3,149 GWh in the 2013 Plan. This represents a 7% decrease in energy reductions. The Company removed two programs from the future category, Commercial Data Center/Computer Room Program and Residential Cool Roof. The Company will continue to monitor these programs for inclusion in future integrated resource plans.

5.5.8 LOAD DURATION CURVES

The Company has provided load duration curves for the years 2014, 2018, and 2028 in Figures 5.5.8.1, 5.5.8.2, and 5.5.8.3.

Figure 5.5.8.1 LOAD DURATION CURVE 2014

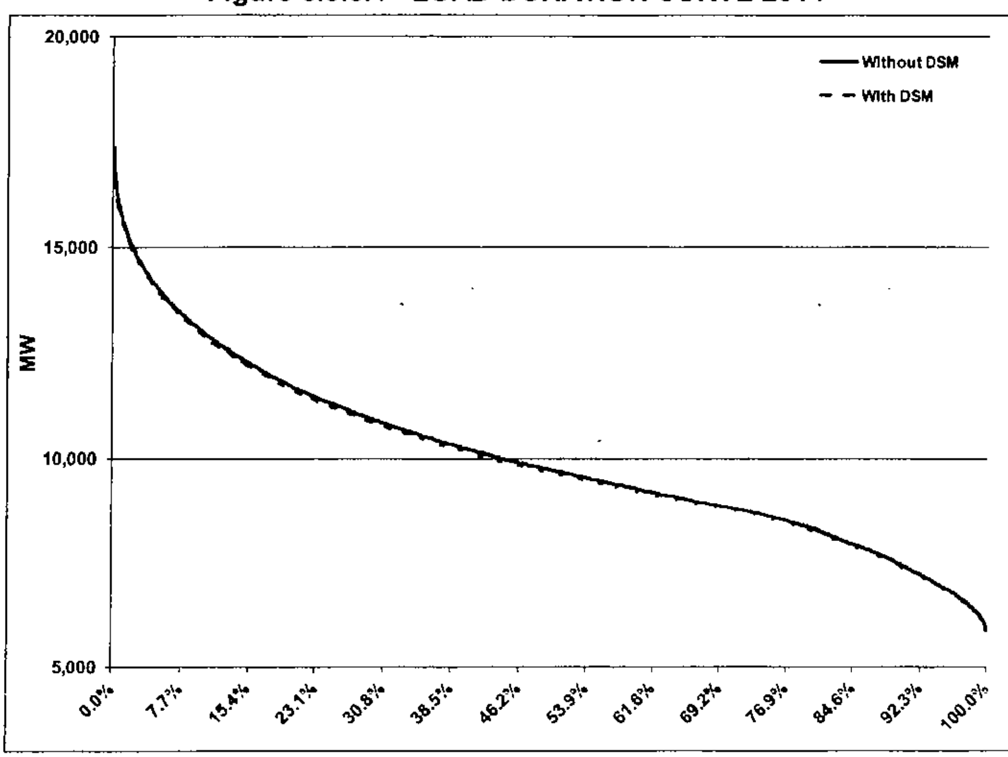


Figure 5.5.8.2 LOAD DURATION CURVE 2018

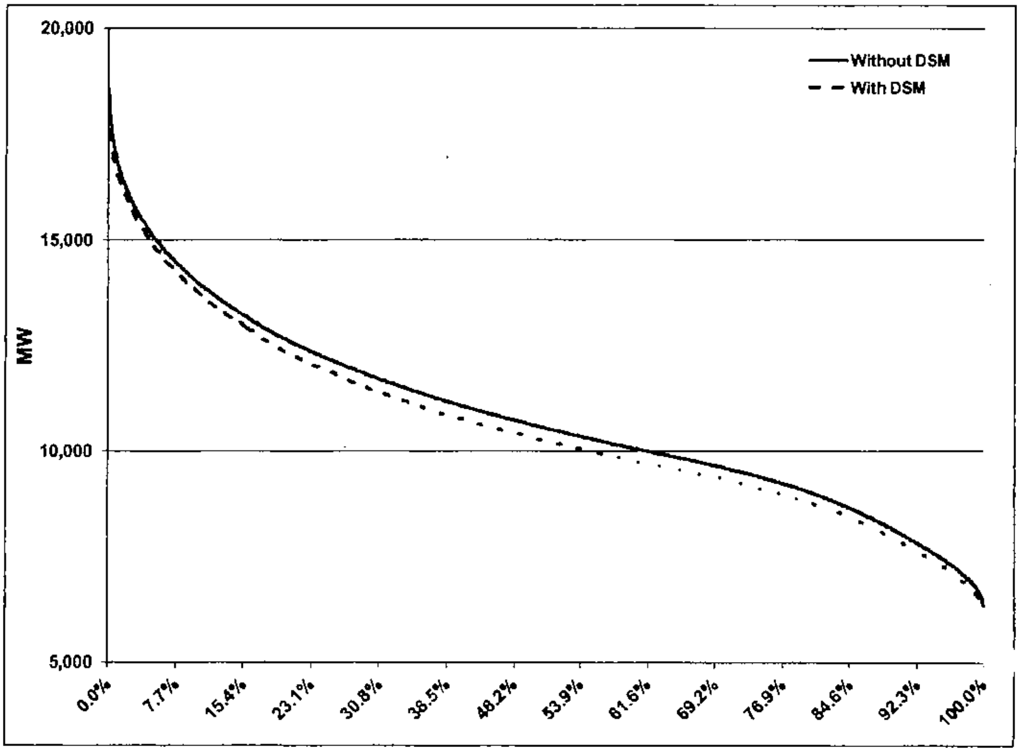
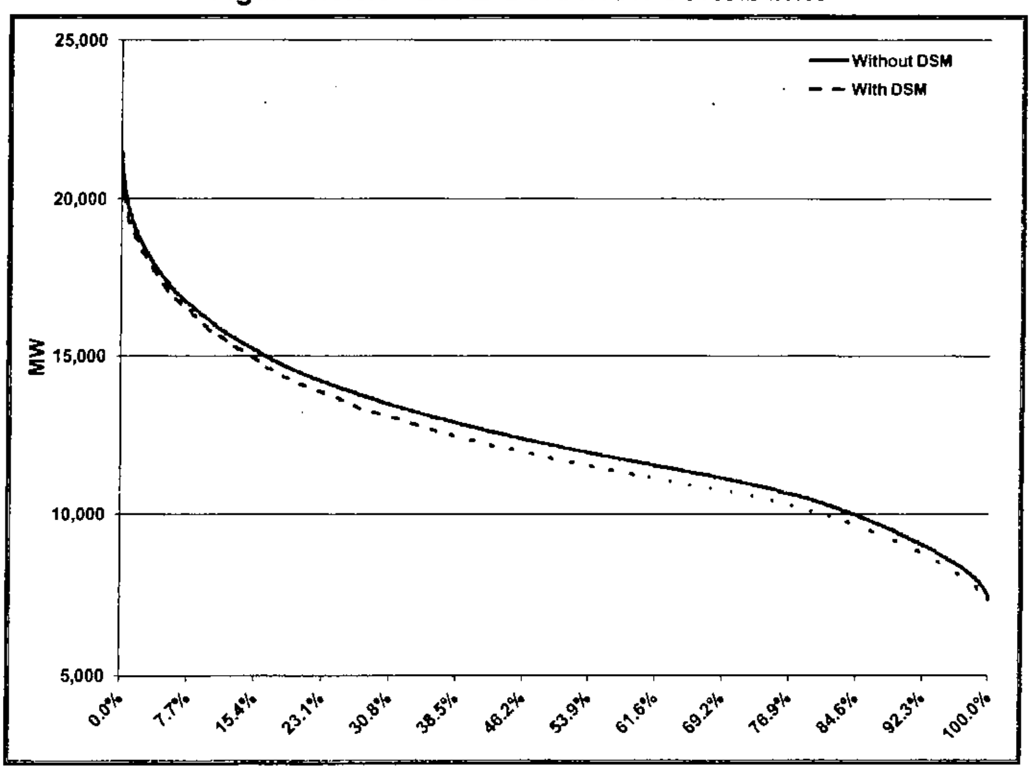


Figure 5.5.8.3 LOAD DURATION CURVE 2028



5.6 FUTURE TRANSMISSION PROJECTS

Appendix 5K provides a list of the Company's transmission interconnection projects for the Planning Period with associated enhancement costs. Extraordinarily Sensitive Appendix 5L provides a list of transmission lines that are planned to be constructed during the Planning Period.

Chapter 6

Development of the Integrated Resource Plan

CHAPTER 6 – DEVELOPMENT OF THE INTEGRATED RESOURCE PLAN

6.1 IRP PROCESS

The IRP process identifies, evaluates, and selects a variety of new resources to meet customers' growing capacity and energy needs to augment existing resources. The Company's approach to the IRP process relies on integrating supply-side resources, market purchases, cost-effective DSM programs, and transmission options over the Study Period. This integration is intended to produce a long-term plan consistent with the Company's commitment to provide reliable electric service at the lowest reasonable cost, while meeting all regulatory and environmental requirements. This analysis develops a forward-looking representation of the Company's system within the larger electricity market that simulates the dispatch of its electric generation units, market transactions, and DSM programs in an economic and reliable manner.

The IRP process begins with the development of a long-term annual peak and energy requirements forecast. Next, existing and approved supply- and demand-side resources are compared with expected load and reserve requirements. This comparison yields the Company's expected future capacity needs to maintain reliable service for its customers over the Study Period.

A feasibility screening, followed by a busbar screening curve analysis is conducted, as described in Chapter 5, to determine supply- and demand-side resources that could potentially fit into the Company's resource mix. These potential resources and their associated economics are then incorporated into the Company's planning model, Strategist. The Strategist model then optimizes the quantity, type, and timing of these new resources based on their economics to meet the Company's future energy and capacity requirements.

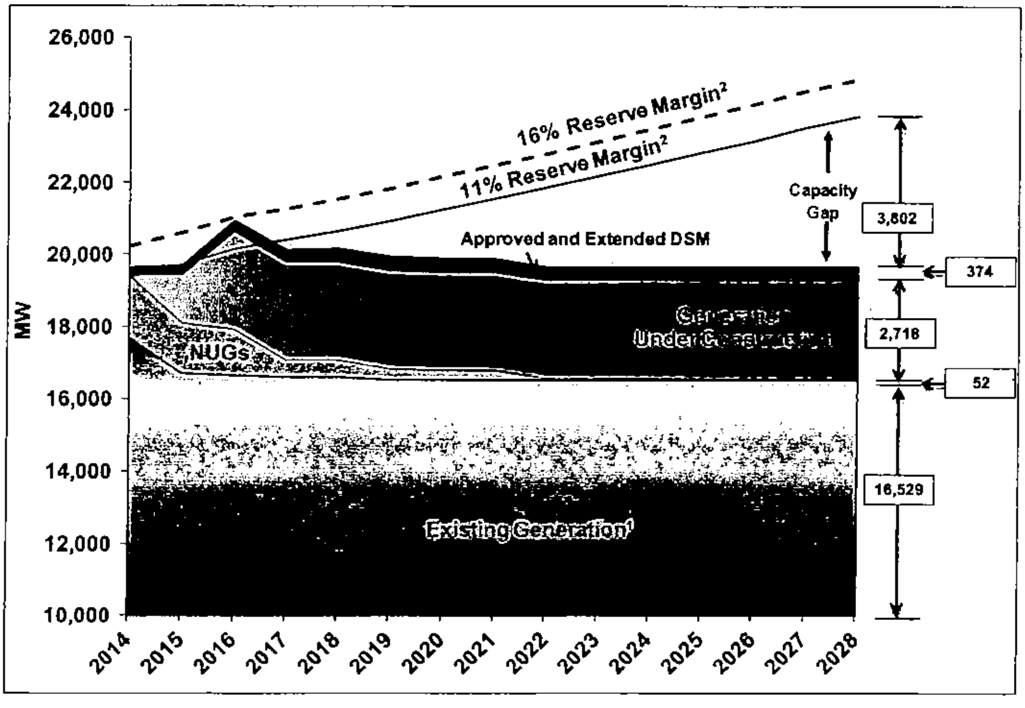
The next step is to develop a set of alternative plans, which represent plausible future paths considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against plausible scenarios that may occur given future market and regulatory uncertainty. Next, the Company creates several scenarios and sensitivities to gauge the strength of each alternative plan as compared to other plans under a variety of conditions represented by these scenarios and sensitivities.

Once the alternative plans are assessed using the various scenarios and sensitivities, the Company finalizes its expansion plan recommendations. These recommendations represent a strategic path forward that the Company maintains will best meet the energy and capacity needs of its customers at the lowest reasonable cost over the Planning Period with due consideration of future risks and uncertainties facing the industry, the Company, and its customers.

6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2 of this 2013 Plan, over the Planning Period, the Company forecasted an average annual growth rate of 1.6% and 1.7% in peak and energy requirements, respectively, for the DOM LSE. Chapter 3 discussed the Company's existing supply- and demand-side resources, NUG contracts, generation retirements, and generation resources under construction. Figure 6.2.1 shows the Company's supply-side resources compared to the capacity requirement, including peak load and reserve margin. The area marked as "capacity gap" shows additional capacity resources that will be needed over the Planning Period in order to meet the capacity requirement. The Company plans to meet this capacity gap using a diverse combination of additional conventional and renewable generating capacity, DSM programs, and market purchases. This analysis considers the economics of each available option within the IRP process, along with qualitative considerations such as fuel diversity and environmental compliance.

Figure 6.2.1 CURRENT COMPANY CAPACITY POSITION (2014 – 2028)



Note: The values in the boxes represent total capacity in 2028.
1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.
2) See Section 4.2.2.

As indicated in Figure 6.2.1, the capacity gap is significant. The Planning Period capacity gap is expected to be approximately 3,800 MW. If this capacity deficit is not filled with additional resources, the reserve margin is expected to fall below the required 11.2% beginning in 2017 and continue to decrease thereafter. Figure 6.2.2 displays actual reserve margins from 2013 to 2028.

Figure 6.2.2 ACTUAL RESERVE MARGIN WITH EXISTING RESOURCES AND GENERATION UNDER CONSTRUCTION

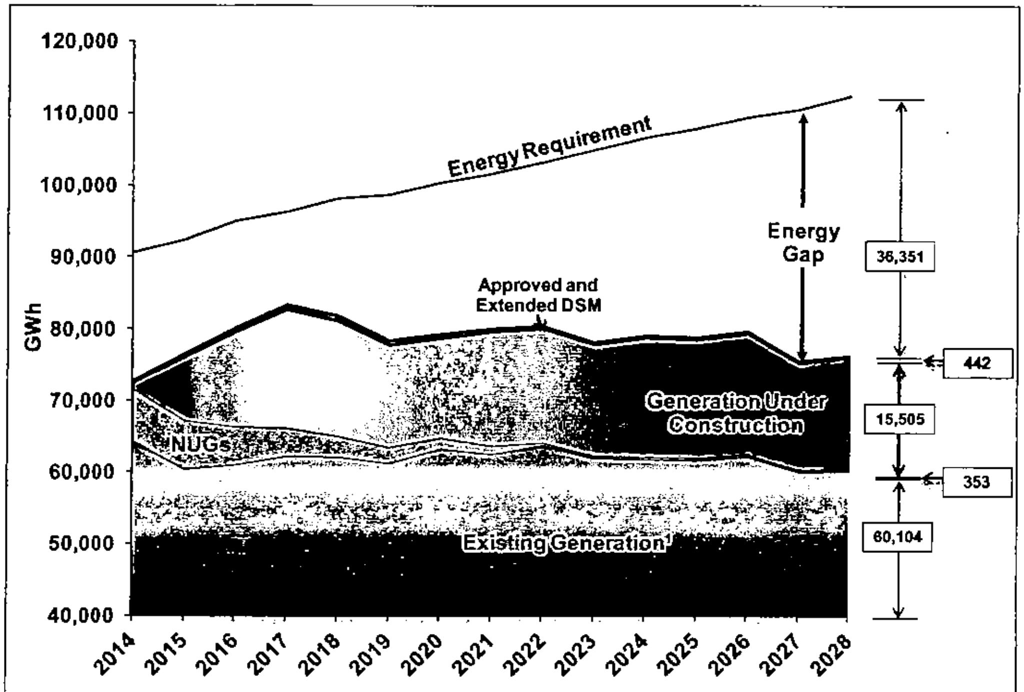
Year	Reserve Margin (%)
2013	15.03%
2014	13.96%
2015	11.36%
2016	15.99%
2017	9.79%
2018	8.62%
2019	5.95%
2020	4.12%
2021	2.55%
2022	-0.02%
2023	-1.47%
2024	-2.88%
2025	-4.24%
2026	-5.60%
2027	-6.99%
2028	-8.23%

The Company's PJM membership has given it access to a wide pool of generating resources for energy and capacity. However, it is critical that adequate reserves are maintained not just in PJM as a whole, but specifically in the DOM Zone to ensure that the Company's load can be served reliably and cost-effectively. Maintaining adequate reserves within the DOM Zone lowers congestion costs, ensures a higher level of reliability, and keeps capacity prices low within the region.

For modeling purposes, the Company assumed that its NUG capacity will be available as a firm resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned/sponsored supply- or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

Figure 6.2.3 illustrates the amount of annual energy required by the Company after the dispatch of its existing resources. The figure shows that the Company's energy requirements increase significantly over time.

Figure 6.2.3 CURRENT COMPANY ENERGY POSITION (2014 – 2028)



Note: The values in the boxes represent total energy in 2028.
1) Accounts for unit retirements and rating changes to existing units in the Plan.

The Company's long-term energy and capacity requirements shown in this section are met through an optimal mix of new conventional and renewable generation, DSM, and market resources using the IRP process.

6.3 RESIDENTIAL RATE ANALYSIS

6.3.1 BACKGROUND

Historically, the Company's annual peak demand for electricity has generally occurred in the 4-month summer period of June through September, primarily due to loads associated with air conditioning. The development of the residential declining block rate structure was designed to: 1) reduce the divergence of summer and non-summer (winter) peaks because the summer peak was growing faster than winter; and 2) enhance the efficiency of the Company's infrastructure by fully utilizing additional generation capacity that is available in the winter because of the level of summer generation capacity required for reliability and less restrictive thermal limitations in the winter. The Company's goal in developing declining rates in the eight non-summer months (hereafter, referred to as winter or winter months) was to flatten the annual load shape such that base rates could be as low as possible to customers by spreading fixed costs over a larger number of sales units, while simultaneously reflecting the Company's cost of service.

SB 956

Pursuant to the enactment clause of SB 956[12] and the SCC's Final Order in Case No. PUE-2011-00092, the Company developed rate design analyses to: 1) address the appropriateness of a declining block residential rate for winter months; and 2) identify potential, generalized rate designs. The Company developed four alternative rate studies to evaluate the impacts of price-induced changes in:

- demand and sales levels (peak and price-induced conservation/sales reductions);
- dispatch costs;
- total estimated customer bills; and
- impacts on bills for residential customers with electric vs. non-electric heating.

6.3.2 ALTERNATIVE RESIDENTIAL RATE DESIGNS

The Company's rate group developed four alternative residential rate designs to be used as model inputs to the Company's load forecasting models, including two rate designs that were previously considered by the SCC in Case No. PUE-2011-00027. The third and fourth rate designs, which are intended to be revenue neutral on a rate design basis, were developed to provide additional clarity to long-term rate impacts as determined by the Company's long-term forecasting models. The four rate designs used to compare against the current declining block rates in the winter months are listed below, with details in Figure 6.3.2.1. These studies are presented for analytical purposes only subject to the limitations discussed in more detail below. These studies should not be interpreted to be alternative rate design proposals by the Company for the revision of the Company's rates.

Alternative Residential Rate Designs to the Company's Existing Base Rates:

- Study A: Flat rates during summer and winter for both distribution and generation;
- Study B: Inclining block rates during summer and winter with flat distribution rates;
- Study C: Flat winter generation rates with no change in the existing summer generation rates or existing distribution rates; and
- Study D: Increased differential between summer and winter rates for residential customers above the 800 kWh block, i.e., an increase in summer rates and a decrease in winter rates for residential customers using more than 800 kWh per month with no changes to distribution rates.

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[12] 2013 Va. Acts of Assembly, Ch. 721, Enactment Clause 1 (approved March 25, 2013, effective July 1, 2013).

Figure 6.3.2.1 RATE DESIGNS

BASE RATES	Existing Rates	Study A Flat Rate	Study B Inclining Block Rate	Study C Flat Winter Rate	Study D Increased Differential Rate
DISTRIBUTION					
BASIC CUSTOMER CHARGE	$7.00	$7.00	$7.00	$7.00	$7.00
FIRST 800 KWH - DISTRIBUTION	$0.02269	$0.01825	$0.01825	$0.02269	$0.02269
OVER 800 KWH - DISTRIBUTION	$0.01296	$0.01825	$0.01825	$0.01296	$0.01296
GENERATION					
SUMMER MONTHS					
FIRST 800 KWH	$0.03795	$0.03919	$0.03016	$0.03795	$0.03795
OVER 800 KWH	$0.05773	$0.03919	$0.04994	$0.05773	$0.06065
BASE MONTHS					
FIRST 800 KWH	$0.03795	$0.03919	$0.03016	$0.03413	$0.03795
OVER 800 KWH	$0.02827	$0.03919	$0.04994	$0.03413	$0.02732
RIDERS (No Change)					
A4 - TRANSMISSION (RIDERS T & T1)	$0.00752	$0.00752	$0.00752	$0.00752	$0.00752
A5 - ENERGY EFFICIENCY (C1A & C2A)	$0.00053	$0.00053	$0.00053	$0.00053	$0.00053
A6 RIDERS - GEN (R, S, W,B & BW)	$0.00873	$0.00873	$0.00873	$0.00873	$0.00873
FUEL - RIDER A	$0.02942	$0.02942	$0.02942	$0.02942	$0.02942
TOTAL RIDERS PER KWH	$0.04137	$0.04137	$0.04137	$0.04137	$0.04137

6.3.3 COMPANY FORECASTING MODEL

The Company's models use the real (inflation adjusted) price of residential electricity as one input to forecast the level of electricity consumed or demanded. This modeling construct allows the inverse nature of price and quantity to be recognized such that changes in price have the opposite effects on quantity (i.e., law of demand). The price inputs and quantity outputs can then be used to determine the elasticity of demand for electricity or the percent change in quantity divided by the percent change in price.

The residential price variable is an input for both the sales and peak models. Both models utilize a short-term, 12-month moving average, and long-term 6-year moving average price variable. The short-term price is interacted with disposable income and appliance stock to reflect residential consumption changes that may occur as a result of transitional price changes such as fuel or rider rates. The long-term price changes are interacted with weather sensitive residential electricity consumption (heat and cooling stock of appliances) such that long-term durable goods (i.e., heat pumps and air conditioning) will adjust to reflect both appliance alternatives and efficiency improvements in weather sensitive appliance stocks.

6.3.3.1 STUDY METHOD

The primary method used to test the alternative rates is through price or elasticity measures. Price elasticity of demand commonly refers to a change in the quantity demanded given a change in price. The main challenge in developing price responsive models is that all customers have specific demand curves (usage levels and sensitivities to prices among other variables), and it is not feasible to develop individual demand response functions for all customers that the Company serves. Generally, the average reaction to a price change is used to estimate price sensitivity of the Company's customers and hence determines the new quantity of forecasted electricity needed. The method is generally designed for incremental analysis which contemplates only marginal changes in prices. Large changes to pricing structures can have impacts outside of the model's abilities to predict quantity changes (i.e., behavioral changes related to budget, income, or substitution). Therefore, the alternative study results should be interpreted with these limitations in mind.

The modeling methods employed by the Company attempt to isolate the change in quantity-related demand and sales as a result of the alternative pricing structures. Additional observations about the rate and consumption outcomes are provided below (i.e., rate change impacts on particular bill levels and heat pump customer impacts). Changes to the load shape (seasonal peak and energy) and levels of consumption were analyzed in the Strategist model to estimate operational cost differences.

The rate comparison graphs discussed below are static in nature and were developed using annual summer and winter average rates and are for modeling purposes only. All rate changes were implemented immediately in the Company's load forecasting models and are dynamic in nature (2013 estimated rates) so the Company's models could absorb the rate changes over the approximately 6-year window used to model electricity price changes as they relate to peak demand and sales levels. Thus, the analysis is expected to normalize by approximately 2019. All comparisons are made to the base set of assumptions as identified in Figure 6.3.2.1.

6.3.3.2 RESULTS

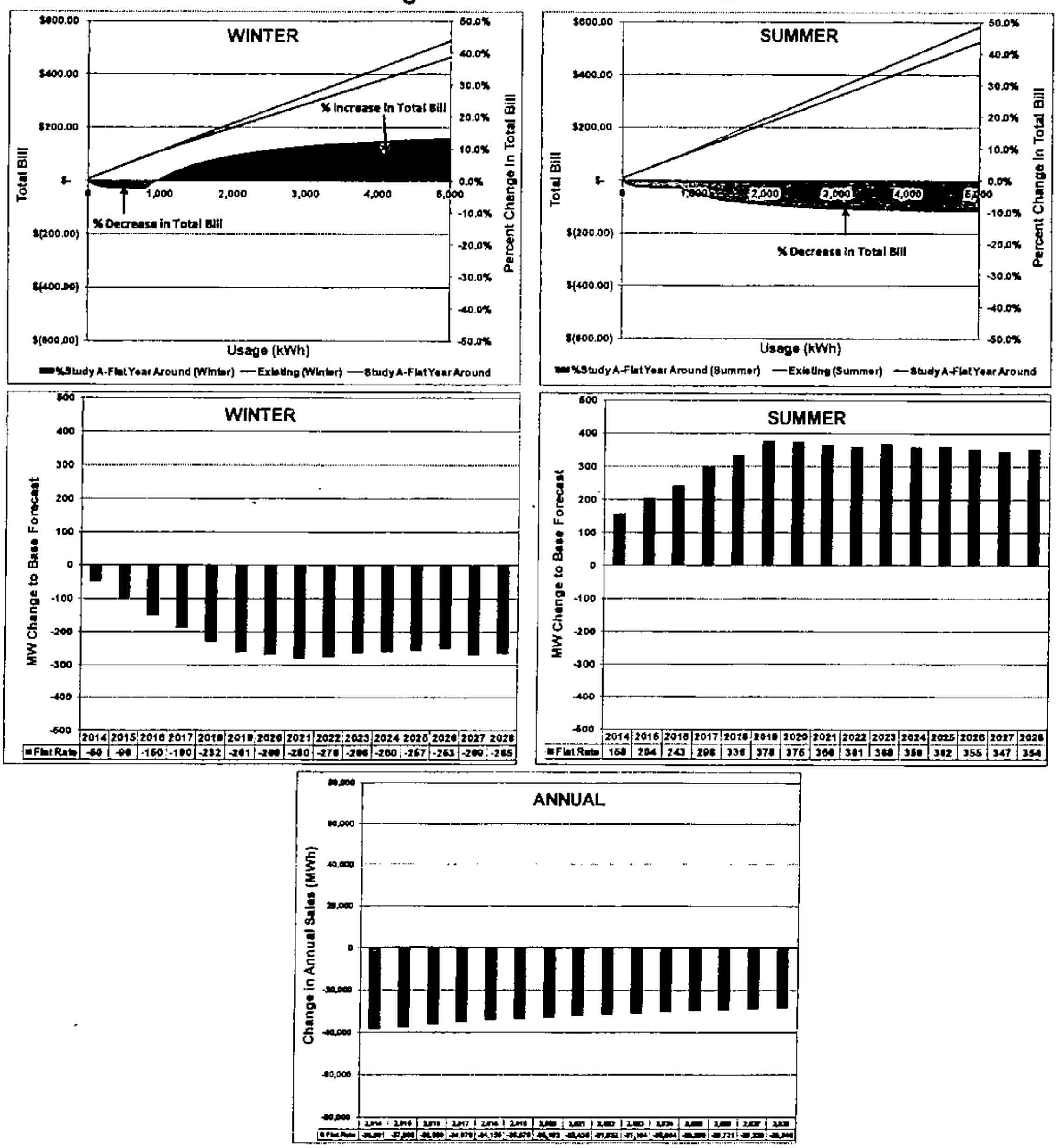
The modeling results follow expectations such that increases in prices lead to lower demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities is approximately -0.07, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.07%. The elasticity suggests that increases in price, holding all other variables constant, will have negative impacts on total sales and peak levels. Price-induced conservation is expected to be bounded by the price elasticity of demand. However, the impact of lower summer rates, as produced in some of the studies, is larger summer peaks which would likely require more capacity or market purchases to maintain reliability. Price changes are not expected to be uniform across the year because of the weighted average effect of seasonal usage levels and the different period of summer (4 months) and winter (8 months) seasonal rates.

The rate studies below estimate the impact on the total bill during the summer and winter periods. The pricing inputs are translated into total bill amounts below to show an instantaneous base rate change that occurs in 2013 relative to the base for both summer and winter rate changes for up to 5,000 kWh of usage. The upward sloping lines represent the total bill under the existing and alternative rate and are measured along the left axis. The shaded area represents the percent change in total bill from the existing to alternative rate and is measured along the right axis. Below each seasonal rate impact slide are charts that reflect the associated change in seasonal peak from 2014 through 2028 that results from the total change in annual rates over time. Finally, the change in annual sales is presented to reflect the appropriate weighted average of each rate study.

Study A: Flat Rate

Year round flat rates over all seasons result in a small decrease of the total bill to low usage customers in both the winter and the summer; however, high usage customers would expect to see significant bill increases in the winter and a smaller percentage reduction in the summer. The peak impacts project a decrease in the winter peak and an increase in the summer peak, thereby requiring the Company to develop or purchase more resources to meet summer peak. Sales are impacted in a negative manner which is reflective of the summer decrease in rate being more than offset by an increase in winter rate which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units. Figure 6.3.3.2.1 provides details on Study A: Flat Rate.

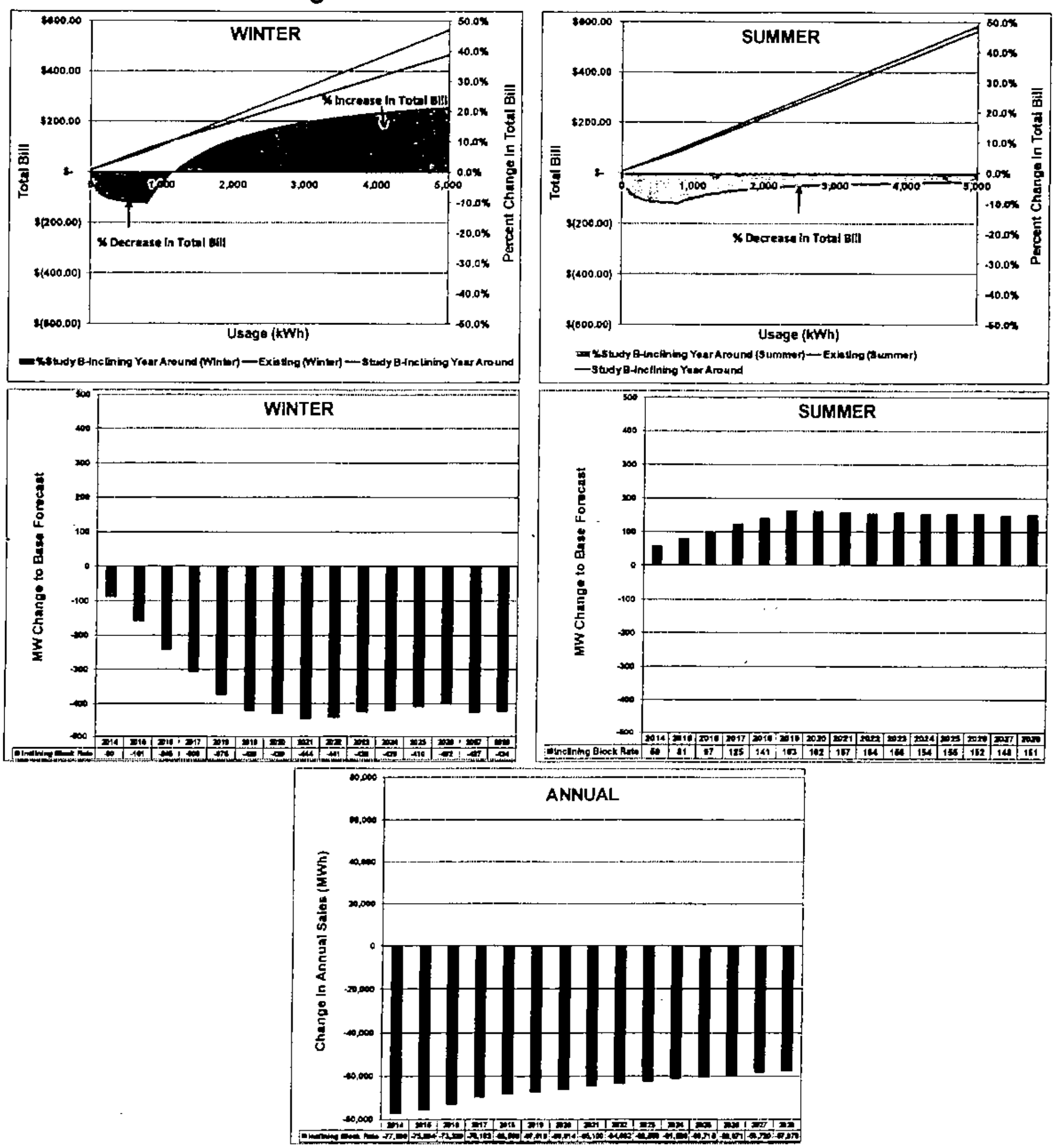
Figure 6.3.3.2.1 FLAT RATE



Study B: Inclining Block Rates

Year round inclining block rates over all seasons result in a fairly significant decrease to low usage customers in both the winter and the summer; however, the bills for high usage customers would increase significantly in the winter with a smaller reduction in the summer. The peak impacts show a large decrease in the winter peak and a smaller increase in the summer peak. Total annual sales are negatively impacted by the large winter rate increase which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units. Figure 6.3.3.2.2 provides details on Study B: Inclining Block Rates.

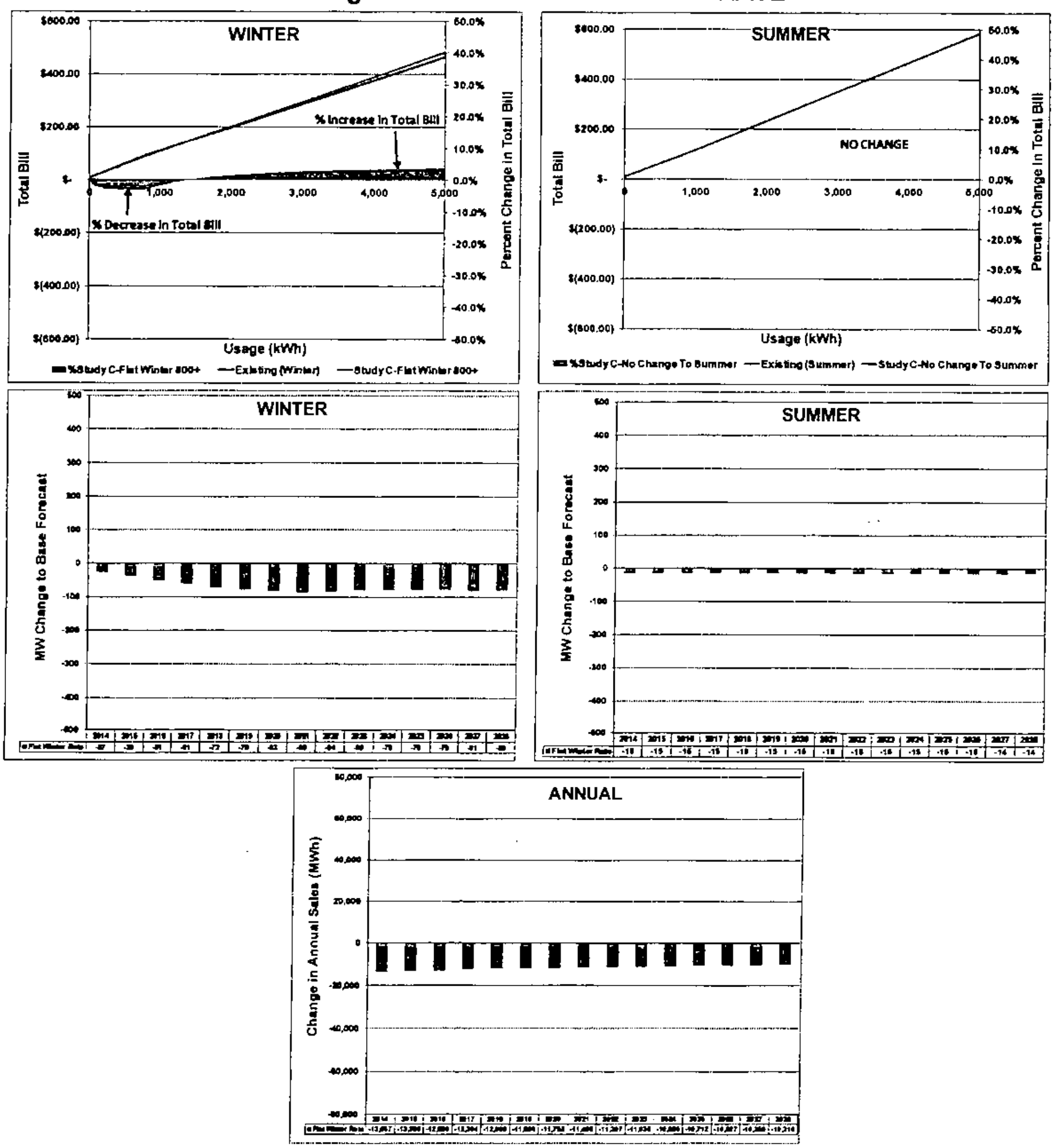
Figure 6.3.3.2.2 INCLINING BLOCK RATES



Study C: Flat Winter Rate (No Change to Summer)

Flat winter rates with no change in the existing summer rate results in a small decrease in the total bill of low usage customers in the winter; however, the bills for high usage customers increase slightly in the winter. No customers' bills would change in summer under the assumptions in the study. The increase in the winter tail-block reduces winter peak and leaves summer peak relatively unchanged. Annual sales are mildly reduced by the winter tail-block rate increase which, in isolation, could result in higher base rates due to costs being recovered over fewer sales units. Figure 6.3.3.2.3 provides details on Study C: Flat Winter Rate.

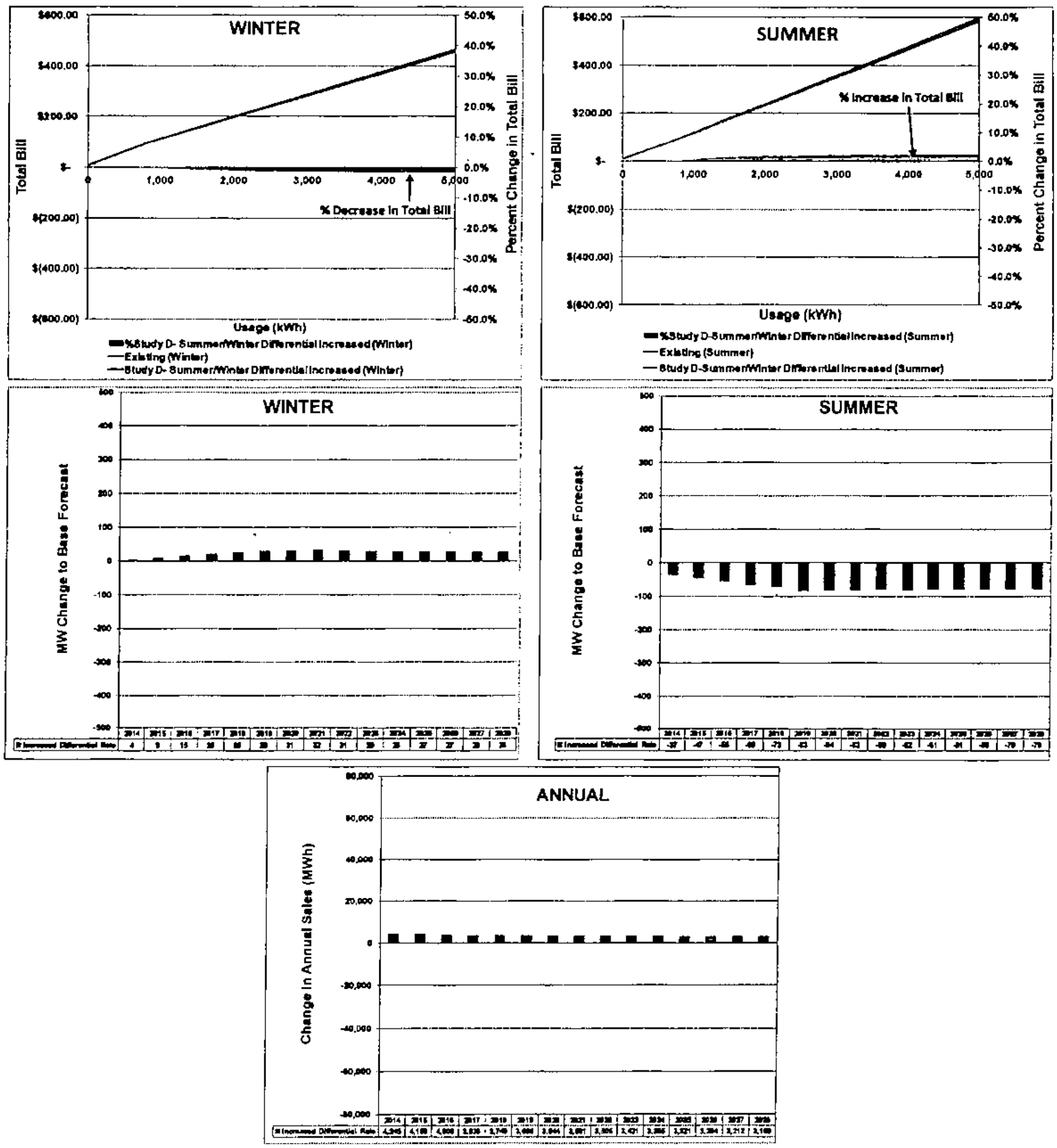
Figure 6.3.3.2.3 FLAT WINTER RATE



Study D: Summer/Winter Differential Increased

Increasing the summer/winter rate differential (summer increase/winter decrease) impacts users above 800+ kWh. Higher usage customers experience slight total bill decreases in the winter and slight total bill increases in the summer. Customers at or below 800 kWh of usage see no change in total bills. Total annual sales increase due to the decrease in winter rates partially offset by the summer rate increase which, in isolation, could result in lower base rates due to costs being recovered over more sales units. Figure 6.3.3.2.4 provides details on Study D: Summer/Winter Differential Increased.

Figure 6.3.3.2.4 SUMMER/WINTER DIFFERENTIAL INCREASED



6.3.3.3 NON-ELECTRIC VS. ELECTRIC HEATING CUSTOMERS

In 2008, the Company conducted an appliance survey for its residential customers to obtain information on the customers' electricity usage. The information from the survey was used to develop two groups for the rate studies, non-electric and electric heating customers. Figure 6.3.3.3.1 provides a summary of the average monthly electricity usage by customer type. These data show similar usage levels during the summer and much higher winter usage for customers who were deemed to have electric heating sources.

Figure 6.3.3.3.1 AVERAGE MONTHLY ELECTRICITY USAGE

Electricity Usage Level by Customer Type (kWh)		
Month	Non-electric Heating Customer	Electric Heating Customer
Jan	946	2,817
Feb	834	2,646
Mar	755	1,956
Apr	793	1,205
May	906	1,057
Jun	1,403	1,398
Jul	1,897	1,730
Aug	1,792	1,639
Sep	1,514	1,415
Oct	1,039	1,073
Nov	807	1,207
Dec	901	2,145
TOTAL	**13,587**	**20,288**

The impact on electric versus non-electric heating customers is summarized by month under each rate study in Figure 6.3.3.3.2. The Company assumed no change in quantity used by customers to isolate the impact of the rate change only. Customers would be expected to change the level of usage and potentially switch to alternative fuel sources if such electric prices were instituted. The Company has not developed a substitution model at this point in time to predict customer switch rates. Switch rates could have large impacts on going forward customer rates because a reduction in total sales would spread fixed generation costs (base rates) over fewer units.

Non-electric heating customers would expect to see annual rate decreases in all cases except Study D which increases the summer winter rate differential because the summer increase more than offsets the winter decrease, but only results in a 0.6% annualized rate increase. Under the other three studies, non-electric heating customers see decreases of between 1.4% and 7% on an annual basis.

Electric heating customers would expect to see annual rate increases in all cases except Study D, which increases the summer winter rate differential, because the summer increase is more than offset by the winter decrease, and results in a 0.3% annualized rate decrease. Under the other three studies, electric heating customers see increases of between 0.6% and 3.5% on an annual basis. However, heating season usage for electric heating customers between December and March shows a significant increase in total bills and could have large impacts on electricity sales by causing customers to switch to alternative fuels, the effects which have not been addressed in this analysis. Increases in the winter price of electricity in Study A and B produce increases in total bills of 9.3% and 13.5%, respectively. Given such bill increases, it is highly likely customers would investigate alternative heating fuels which could have large negative impacts on sales resulting in increased future rate levels.

Figure 6.3.3.3.2 ELECTRIC VS. NON-ELECTRIC HEATING CUSTOMERS

Percent Change in Average Bill - No Change in Quantity									
Rate Change for Non-electric Heating Customer					Rate Change for Electric Heating Customer				
Month	Study A	Study B	Study C	Study D	Month	Study A	Study B	Study C	Study D
Jan	-0.3%	-5.7%	-2.2%	-0.3%	Jan	10.4%	15.7%	2.5%	-1.4%
Feb	-2.1%	-9.3%	-3.0%	-0.1%	Feb	10.0%	14.9%	2.3%	-1.4%
Mar	-2.8%	-10.5%	-3.3%	0.0%	Mar	7.7%	10.4%	1.3%	-1.2%
Apr	-2.8%	-10.6%	-3.3%	0.0%	Apr	2.8%	0.6%	-0.8%	-0.6%
May	-0.9%	-6.9%	-2.5%	-0.2%	May	1.2%	-2.7%	-1.6%	-0.4%
Jun	-6.5%	-6.9%	0.0%	1.1%	Jun	-6.5%	-6.9%	0.0%	1.1%
Jul	-7.7%	-5.7%	0.0%	1.4%	Jul	-7.4%	-6.0%	0.0%	1.3%
Aug	-7.5%	-5.9%	0.0%	1.4%	Aug	-7.2%	-6.2%	0.0%	1.3%
Sep	-6.8%	-6.6%	0.0%	1.2%	Sep	-6.5%	-6.9%	0.0%	1.1%
Oct	0.9%	-3.2%	-1.7%	-0.4%	Oct	1.4%	-2.3%	-1.5%	-0.5%
Nov	-2.6%	-10.3%	-3.2%	0.0%	Nov	2.8%	0.6%	-0.8%	-0.6%
Dec	-1.0%	-7.1%	-2.5%	-0.2%	Dec	8.5%	11.9%	1.6%	-1.2%
TOTAL	**-4.2%**	**-7.0%**	**-1.4%**	**0.6%**	**TOTAL**	**2.2%**	**3.5%**	**0.6%**	**-0.3%**
Winter Change	**-1.4%**	**-7.7%**	**-2.7%**	**-0.2%**	**Winter Change**	**6.8%**	**8.6%**	**0.9%**	**-1.1%**
Summer Change	**-7.2%**	**-6.2%**	**0.0%**	**1.3%**	**Summer Change**	**-6.9%**	**-6.5%**	**0.0%**	**1.2%**
Heating Season (Dec-Mar)	**-1.5%**	**-8.0%**	**-2.7%**	**-0.1%**	**Heating Season (Dec-Mar)**	**9.3%**	**13.5%**	**2.0%**	**-1.3%**

6.3.3.4 APPROPRIATENESS OF THE DECLINING BLOCK RATE

Based on the results of these studies, the Company maintains that the declining winter block rate is an appropriate rate mechanism to utilize generation capacity efficiently on an annualized basis, control summer peak growth, and keep rates low and affordable, particularly for electric heating customers. While the study results presented above begin to reveal correlations and relationships between price and quantity, these analyses should be viewed as initial benchmark studies of alternative rate designs.

Large pricing changes as suggested in Study A and Study B make model outputs less reliable than would be desired to establish alternative rate designs. Additionally, the studies contemplate an instantaneous shift in rate design, rather than a long-term incremental approach to rate changes which allows customers to react and avoid large rate increases. For example, customers' investments in long-term electric-based infrastructure, such as heat pumps, could be significantly impacted under alternative rate studies in a negative fashion.

In future Virginia integrated resource plans, the Company may consider studying multiple price/quantity points in its models going forward rather than the average price/quantity effects reflected in this study. These future studies could lead to potential rate designs, as suggested by the SCC's Final Order in Case No. PUE-2011-00092. Additionally, there is insufficient information regarding the impacts of fuel switching or substitution from electricity to natural gas on winter sales in Virginia to draw any conclusions at this time.

6.4 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares the costs of alternative plans to evaluate the types and timing of resources that were included in those plans. The first step in the process was to construct a representation of the Company's current resource base. Then, future assumptions including, but not limited to load, fuel prices, emissions costs, maintenance costs, and resource costs were used as inputs to Strategist. Concurrently, supply-side resources underwent an initial screening analysis as discussed in Chapter 5. This analysis provided a set of future supply-side resources potentially available to the Company, along with their individual characteristics. Supply-side resources that are available to the Strategist model are shown in Figure 6.4.1.

Figure 6.4.1 SUPPLY-SIDE RESOURCES AVAILABLE IN STRATEGIST

Dispatchable
Biomass
CC 2x1
CC 3x1
Coal w/CCS
CT
Fuel Cell
IGCC CCS
Nuclear (NA3)
Non Dispatchable
Offshore Wind
Onshore Wind
Solar NUG
Solar PV
Solar Tag

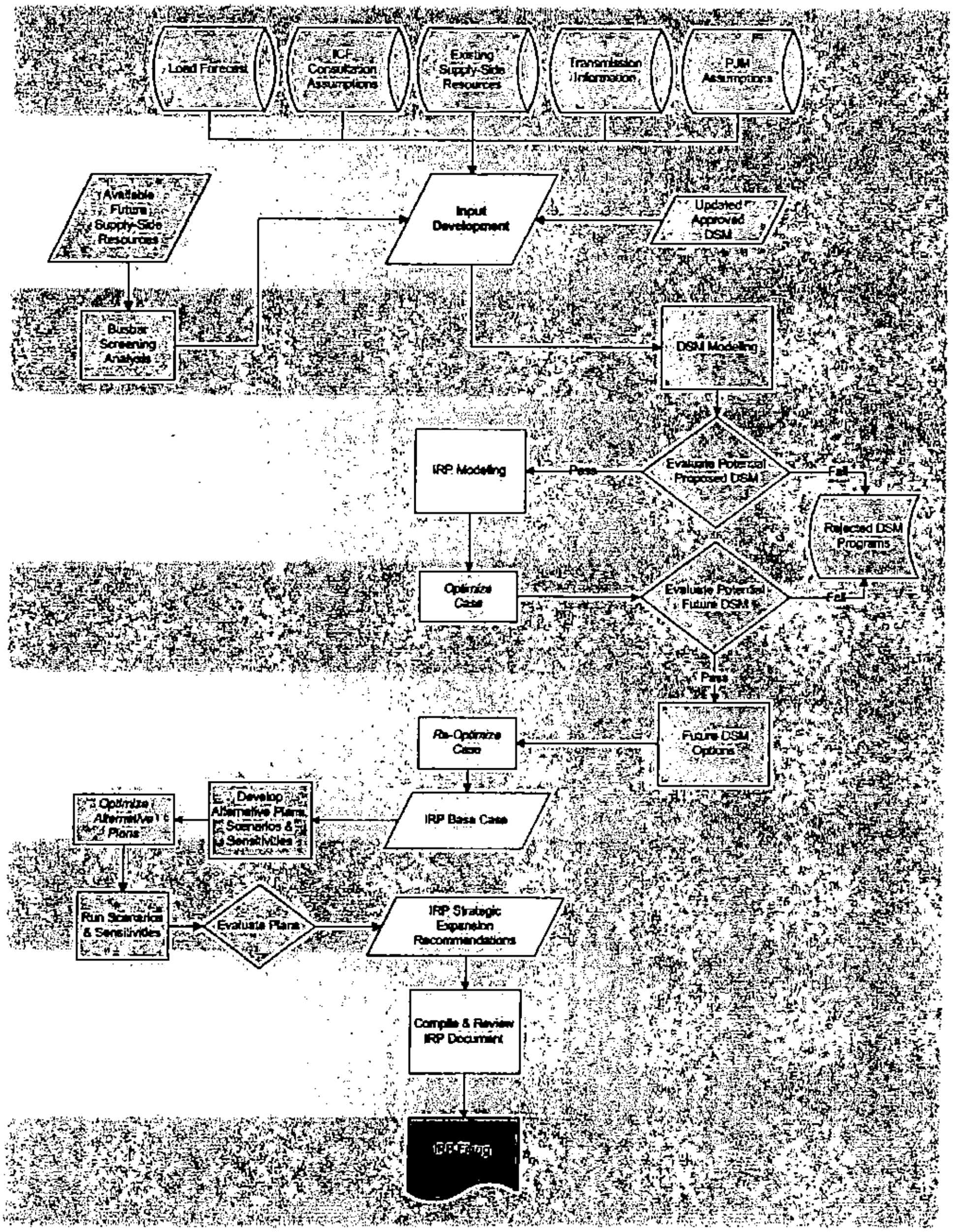
***Key:** CC: Combined-cycle; CT: Combustion Turbine (2 units); IGCC CCS: Integrated-Gasification Combined-cycle with Carbon Capture and Sequestration; Coal CCS: Coal with Carbon Capture and Sequestration; Solar PV: Solar Photovoltaic; Solar Tag: Solar Tag along to generation site.*

As described in Chapter 5, potential DSM resources were also screened. For the initial screening of demand-side resource options, an expansion plan of only supply-side resources and approved, extended, and proposed DSM programs was developed. The extended and future DSM programs that passed the Company's cost/benefit evaluation discussed in Section 5.5.1 were compared to this initial plan with the opportunity to modify the expansion plan based on their economics. After cost-effective demand-side resources were identified, they were included as a portfolio of programs that was given the opportunity to eliminate, defer, or alter the need for future supply-side resources and market purchases. Next, supply-side options, market purchases and approved, extended and proposed demand-side resource options were re-optimized along with the future DSM portfolio to arrive at a Base Plan. This process ensured that supply- and demand-side resources were placed on equal footing to meet peak capacity and energy requirements.

Strategist develops resource plans based on the total net present value ("NPV") utility costs over the Study Period. The NPV utility costs included the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

To assess an optimum resource strategy and the validity of the Company's 2013 Plan, the Company developed six alternative plans representing plausible future paths, as described in Section 6.5. All six alternative plans were then analyzed and tested against a set of scenarios and sensitivities designed to measure the relative cost performance of each plan under varying market, commodity, and regulatory conditions. Based on the results of this quantitative comparison analysis along with qualitative considerations such as reliability and fuel diversity, the Company developed recommendations for its going forward strategic expansion. Figure 6.4.2 displays the Company's Plan development process.

Figure 6.4.2 PLAN DEVELOPMENT PROCESS



Key: *Cylinder: Model Input/Assumption Data; Diamond: Evaluation/Decision Phase; Flag: Regulatory Filing/Document; Square: Data Modeling; Parallelogram: Data/Strategist Case; Rectangle: Strategist Optimization.*

6.5 ALTERNATIVE PLANS

The Company's alternative plan analysis is intended to represent plausible paths of future resource additions. Each alternative plan is given certain characteristics. For example, Plan B includes a nuclear unit being constructed along with onshore wind and solar in the Planning Period, Plan C includes selected amounts of renewable generation being constructed throughout the Planning Period. After this step, each alternative plan was then optimized around the Company's basecase assumptions, where each individual plan was able to select from the resources shown in Figure 6.4.1 in order meet peak capacity and energy requirements through the Study Period.

Along with the individual characteristics of the alternative plans, the plans also share a number of individual generation resource assumptions. Each alternative plan includes the resources for which the Company has filed and/or has been granted CPCN approval from the SCC. These resources include Warren County Power Station, Brunswick County Power Station, the conversion of Bremo Units 3 and 4 from coal to natural gas, the conversion from coal to biomass of Altavista, Hopewell, and Southampton Power Stations, and the SPP.

Also selected in every alternative plan are the retrofits at Possum Point 5 and Yorktown 3 by 2018. All alternative plans have the same level of approved and extended, and proposed and future DSM programs reaching 544 MW by the end of the Planning Period. Additionally, each alternative plan reflects the retirement of Chesapeake Energy Center Units 1 (111 MW), 2 (111 MW), 3 (156 MW), and 4 (217 MW) and Yorktown Units 1 (159 MW) and 2 (164 MW) by 2015. The EEP, EP&S, and solar NUGs are also selected (total 85 MW nameplate) in 2015. The Company's six alternative plans are described in greater detail below.

Plan A: Base Plan

The Base Plan does not include any additional plan characteristics. The Base Plan was developed using least cost modeling methodology. Specifically, Plan A selects:

- 2,750 MW of CC capacity (two CCs);
- 1,371 MW of CT capacity (three banks of 2 CTs – 457 MW per bank).

Plan B: Fuel Diversity

Plan B is designed to address considerations such as reliability, fuel diversity, price stability, and environmental compliance for the Company's customers over the Planning Period. Plan B includes:

- 1,453 MW North Anna 3 nuclear facility;
- 247 MW (nameplate) of onshore wind;
- 12 MW Offshore Wind Demonstration Project;
- 200 MW (nameplate) of generic solar;
- 20 MW (nameplate) of solar tag comprised of two 10 MW units;

And selects:

- 1,375 MW of CC capacity (one CC);
- 1,371 MW of CT capacity (three banks of 2 CT units – 457 MW per bank).

Plan C: Renewable

The Renewable Plan presents a way for the Company to test the feasibility and cost of meeting Virginia's RPS goals as well as North Carolina's REPS requirements through increased building of new renewable resources.

The Virginia legislature enacted Va. Code § 56-585.2, establishing a voluntary RPS program with a goal that increases by year stating that it is in the public interest for utilities to achieve the targets set forth in Virginia's RPS program. Additionally, the Virginia legislature has indicated that small renewable energy projects are in the public interest (Va. Code § 56-580.D). Similarly, the North Carolina legislature has established REPS (NCGS § 62-133.8) with mandatory renewable requirements that increase by year and include specific requirements for solar, swine waste, and poultry waste.

To meet these targets with new Company-owned resources, the Company would be required to develop an additional significant amount of renewable resources compared to all other plans. This plan includes:

- 100 MW of generic biomass;
- 247 MW (nameplate) of onshore wind;
- 1,600 MW (nameplate) of offshore wind;
- 12 MW Offshore Wind Demonstration Project;
- 200 MW (nameplate) of generic solar;
- 20 MW (nameplate) of solar tag.

And selects:

- 2,750 MW of CC capacity (two CCs);
- 1,371 MW of CT capacity (three banks of 2 CT units – 457 MW per bank).

Plan D: Coal

In response to questions related to the cost and feasibility related to developing coal facilities in Case No. PUE-2011-00092, as required by the Final Order, the Company developed Plan D: Coal. The Coal Plan considers the Company developing generic pulverized coal ("PC")-fired facilities with carbon capture and sequestration technology. These PC CCS units are approximately 640 MW each. This plan only considers coal facilities with CCS. Coal facilities without CCS will not meet the requirements of the EPA's NSPS and are therefore not feasible under existing laws. This plan includes:

- 1,920 MW of PC CCS (three 640 MW units);

And selects:

- 1,375 MW of one CC;
- 457 MW CT capacity (one bank of 2 CT units).

Plan E: Climate Action Plan

Plan E is designed as one possible outcome that could occur under the President's CAP announced in June 2013. Under Plan E, all coal-fired generation facilities failing to achieve an existing heat rate of 10,000 Btu/kWh or better would have to retire. In addition, this Plan assumes that no more than 67% of the Company's generation can come from natural gas fired generation (a carbon emitting fuel). This Plan includes 2,125 MW of coal retirements, and also includes:

- 247 MW (nameplate) of onshore wind;
- 12 MW Offshore Wind Demonstration Project;
- 200 MW (nameplate) of generic solar;
- 20 MW (nameplate) of solar tag.

And selects:

- 1,453 MW North Anna 3 nuclear facility;
- 2,750 MW of CC capacity (two CCs);
- 1,371 MW of CT capacity (two banks of 3 CTs – 457 MW per bank).

Plan F: Offshore Wind

The Offshore Wind Plan represents a plan with significant offshore wind. Specifically, Plan F includes:

- 1,600 MW of offshore wind;
- 12 MW Offshore Wind Demonstration Project.

And selects:

- 1,375 MW of CC capacity (one CC);
- 1,828 MW of CT capacity (four banks of 2 CT units - 457 MW per bank).

Figure 6.5.1 ALTERNATIVE PLANS

Year	Plan A Base		Plan B Fuel Diversity		Plan C Renewable	
	Conventional	Renewable/DSM	Conventional	Renewable/DSM	Conventional	Renewable/DSM
2014		App.DSM/SPP		App.DSM/SPP		App.DSM/SPP
2015	Warren	Fut.DSM/EEP SLRNUG/ EP&S/ SPP	Warren	Fut.DSM/EEP SLRNUG/ EP&S/ SPP	Warren	Fut.DSM/EEP SLRNUG/ EP&S/ SPP/ FUELCELL
2016	Brunswick		Brunswick		Brunswick	
2017				SLR TAG / SLR		SLR TAG/ SLR
2018				OFFD / SLR		OFFD / SLR
2019	CC		CC	SLR	CC	BIO/ SLR
2020				SLR TAG / SLR		BIO/ SLR TAG/ SLR
2021	CT			SLR		SLR
2022	CT		CT	WND	CT	WND
2023	CT			WND	CT	WND/ OFF
2024				WND		WND/ OFF
2025			NA3		CT	OFF
2026						
2027	CC		CT		CC	
2028			CT			

Year	Plan D Coal		Plan E Climate Action Plan		Plan F Offshore Wind	
	Conventional	Renewable/DSM	Conventional	Renewable/DSM	Conventional	Renewable/DSM
2014		App.DSM/SPP		App.DSM/SPP		App.DSM/SPP
2015	Warren	Fut.DSM/EEP SLRNUG/ EP&S/SPP	Warren	Fut.DSM/EEP SLRNUG/ EP&S/SPP	Warren	Fut.DSM/EEP SLRNUG/ EP&S/SPP
2016	Brunswick		Brunswick		Brunswick	
2017				SLR TAG / SLR		
2018				OFFD / SLR		OFFD
2019	CC		CC	SLR	CC	
2020			CT	SLR TAG / SLR		
2021	CT		CT / CT	SLR	CT	
2022	COAL CCS		CC	WND	CT	
2023				WND		OFF
2024	COAL CCS			WND	CT	OFF
2025			NA3			OFF
2026	COAL CCS				CT	
2027						
2028						

Key: *App. DSM: Approved & Extended DSM Programs; Bio: Biomass; Brunswick: Brunswick County Power Station; CC: Combined-cycle 3x1; SPP: Solar Partnership Program; COAL CCS: Coal w/ Carbon Capture Sequestration; CT: Combustion Turbine (2 units); EEP: Energy Extraction Partners; EP&S: Economic Power & Steam Generation, LLC; NA3: North Anna Unit 3; OFF: Offshore Wind; OFFD: Offshore Wind Demonstration Project; Fut. DSM: Proposed & Future DSM Programs; SLR: Generic Solar; SLR NUG: Solar NUG; SLR TAG: Solar Tag; Warren: Warren County Power Station; WND: Onshore Wind.*

Note: 1) *DSM capacity continues to increase throughout the Planning Period.*

6.6 BASECASE, SCENARIOS & SENSITIVITIES

The Company used a number of scenarios and sensitivities based upon its planning assumptions to evaluate these six alternative plans. The Company's operational environment is highly dynamic and can be significantly impacted by variations in commodity prices, construction costs, environmental, and regulatory requirements. Testing multiple expansion plans under different assumptions assesses each plan's cost performance under a multitude of possible future outcomes. The Company examined one basecase, three scenarios, and 13 sensitivities as explained below.

Basecase (1)

The basecase used the expected or forecast "base" values including the load forecast (Chapter 2), existing system resources (Chapter 3), planning assumptions (Chapter 4), and new resources (Chapter 5).

Scenarios:

Scenarios provide a broad range view of the variable future evolution of the markets and regulatory conditions. Several key assumptions were changed in each scenario, which accounted for systemic changes in the view of the future. These changes included multiple variables that were interrelated, such as emission and cost variables, ensuring all assumptions were consistent. The Company examined (a) no carbon cost, (b) high fuel cost, and (c) low fuel cost.

No Carbon Cost Scenario (2)

One of the most significant uncertainties for the electric utility industry is whether and when industry-wide carbon legislation/regulation will be enacted for supply-side resources and, if it occurs, its structure and potential impacts on the fuel markets. The Company's basecase assumes that carbon legislation/regulation will be enacted by 2023. The assumed program is structured as a carbon tax efficiency requirement that would increase the cost of generating electricity using fossil fuels because of their carbon emissions. Until a specific law is passed or regulation is enacted, uncertainty remains regarding program design, cost, and timing.

Due to these uncertainties, the Company chose to examine a scenario where there would be no cost of carbon emissions in the Study Period; fuel and commodity processes were correlated appropriately to the effects of removing the modeled CO_2 market. The assumptions that were adjusted in this scenario include: i) fossil fuel prices (coal, gas, and oil); ii) environmental allowance prices (SO_2 and NO_X); iii) market capacity and energy prices; and iv) REC prices.

High and Low Fuel Cost Scenarios (3-4)

These scenarios were designed to test fuel price variations for all generation units in each alternative plan, because fuel costs are a significant portion of final customer rates. Volatility in rates is generally viewed as undesirable; therefore, plans that reduce volatility may be preferred to other alternative plans. These scenarios consider adjustments to the following assumptions (with the changes in the fuel prices being the main driver): i) fossil fuel prices (coal, gas, and oil); ii) environmental allowance prices (SO_2, NO_X, and CO_2); iii) market capacity and energy prices; and iv) REC prices.

Sensitivities:

A sensitivity represents a change in a single or small subset of variables from the basecase assumptions. The sensitivities performed by the Company were designed to test the alternative plans under varying assumptions to better understand the inherent risks embedded in the Company's 2013 Plan. The Company performed the following 13 sensitivities:

High and Low Load Growth Sensitivities (5-6)

Future load growth was one of the key inputs used to develop the 2013 Plan. Demand growth is significantly impacted by regional economic growth and technological changes. As discussed in Chapter 2, the basecase average annual growth rate over the Planning Period for the DOM LSE is 1.6% and 1.7%, respectively, for peak and energy requirements. The high and low load growth sensitivities assume a plus and minus 0.5% change in these average annual growth rates (see Figure 6.6.1). The high load growth sensitivity could result from an above average economic growth rate or expanded penetration of new technological devices at home and in the workplace. The low load growth sensitivity may come from lower than expected economic growth, additional energy conservation, or a decline in real disposable income.

Figure 6.6.1 SUMMARY OF HIGH LOAD AND LOW LOAD SENSITIVITIES

YEAR	Peak (MW)		Energy (GWh)	
	High Load	Low Load	High Load	Low Load
2014	17,509	17,339	90,077	89,204
2015	18,058	17,709	93,062	91,268
2016	18,523	17,987	95,572	92,818
2017	18,946	18,219	97,417	93,680
2018	19,363	18,438	99,552	94,797
2019	19,803	18,672	101,814	96,003
2020	20,212	18,871	104,416	97,497
2021	20,704	19,142	106,541	98,506
2022	21,158	19,370	108,941	99,740
2023	21,611	19,591	111,369	100,965
2024	22,053	19,796	114,104	102,435
2025	22,465	19,968	116,255	103,342
2026	22,916	20,169	118,719	104,498
2027	23,398	20,391	121,026	105,484
2028	23,878	20,606	123,675	106,738

High and Low Construction Cost Sensitivities (7-8)

The escalation of power plant construction costs could represent a significant risk for the Company's customers. Potential increase in construction costs represents a significant challenge to utilities, regulators, and customers across the United States as utilities focus on replacing aging infrastructure and adding new capacity to meet current regulatory requirements and future demand growth. The construction cost sensitivities analyzed the risk associated with potential future increases or decreases in the construction costs of traditional and renewable plants. The high and low construction cost sensitivities assumed an increase and decrease of costs by 25% in order to determine the economic impact of potential changes in the construction cost of new units.

High and Low Transmission and Distribution Cost ("T&D") Sensitivities (9-10)

The Company assumed that a portion of the benefits from the Company's portfolio of DSM programs was from avoided T&D investments to meet incremental demand growth. The costs estimated for incremental T&D projects have increased in recent years in a similar fashion to generation construction projects. As a result, the high and low T&D cost sensitivities of the approved, extended, and future DSM programs were tested by increasing and decreasing the T&D benefit of the DSM programs by 25%.

Net Metering (11)

In Virginia, net metering is currently available to customers on a first-come, first-serve basis in each electric distribution Company's service area. This occurs until the rated generating capacity owned and operated by eligible customer generators reaches 1% of each electric distribution Company's adjusted Virginia peak load forecast for the previous year (see Figure 6.6.2). This sensitivity will allow the Company to determine the impact on load in the event that the 1% cap is reached in Virginia by 2038. In North Carolina, there is no aggregate capacity limit for net metering.

Figure 6.6.2 SUMMARY OF NET METERING SENSITIVITY

Year	Energy (GWh)	Capacity (MW)	Coincident Peak Impact (MW)
2014	12.35	7.95	2.21
2015	14.22	9.15	2.54
2016	16.37	10.54	2.93
2017	18.84	12.13	3.37
2018	21.69	13.96	3.88
2019	24.97	16.08	4.47
2020	28.75	18.51	5.14
2021	33.09	21.30	5.92
2022	38.10	24.53	6.82
2023	43.86	28.23	7.85
2024	50.49	32.50	9.04
2025	58.12	37.42	10.40
2026	66.91	43.07	11.97
2027	77.02	49.58	13.78
2028	88.67	57.08	15.87

Electric Vehicles Sensitivity (12):

The Company's basecase assumed approximately 0.2 million EVs and PHEVs in its service territory by 2028, with penetrations increasing throughout the Study Period (see Figure 6.6.3). Peak demand and energy requirements due to EVs and PHEVs in the basecase reach 119 MW and 641 GWh by 2028. This sensitivity relies on the EPRI's PHEV study[13] for a higher penetration of 0.85 million PHEVs. The objective of the EV and PHEV sensitivity was to project the impact of higher plug-in EV penetration on the Company's grid and identify resources needed to meet this potential new technology's requirements.

Figure 6.6.3 SUMMARY OF ELECTRIC VEHICLE SENSITIVITY

Year	Base Forecast			EV Sensitivity		
	EV Count	Peak (MW)	Energy (GWh)	EV Count	Peak (MW)	Energy (GWh)
2014	5,312	19	15	14,972	54	42
2015	10,058	36	28	33,956	122	96
2016	16,387	59	46	59,270	213	167
2017	24,297	88	68	90,911	327	256
2018	33,789	122	95	128,881	464	363
2019	44,864	162	126	173,179	624	488
2020	57,520	207	162	223,805	806	631
2021	71,759	258	202	280,760	1,011	791
2022	87,580	315	247	344,043	1,239	970
2023	104,983	378	296	413,654	1,490	1,166
2024	123,967	447	349	489,593	1,763	1,380
2025	144,534	521	407	571,861	2,060	1,612
2026	166,683	600	470	660,457	2,379	1,861
2027	190,415	686	537	755,382	2,721	2,129
2028	215,728	777	608	856,634	3,086	2,414

No REC Sales Sensitivity (13)

In this sensitivity, the Company assumed that it would not be able to sell RECs, therefore increasing the net cost of renewable generation, see Figure 6.6.4.

High REC Sales Sensitivity (14)

This sensitivity assumed that renewable generation resources will produce a REC that has twice the value of a basecase REC. See Figure 6.6.4 for a summary of the REC Sales sensitivities.

[13] This study is available at http://www.epri.com.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

Figure 6.6.4 SUMMARY OF REC SALES SENSITIVITIES

Year	Tier I RECs ($/MWh)		
	Base Case	High REC Sales	No REC Sales
2014	[redacted]	[redacted]	0.00
2015	[redacted]	[redacted]	0.00
2016	[redacted]	[redacted]	0.00
2017	[redacted]	[redacted]	0.00
2018	[redacted]	[redacted]	0.00
2019	[redacted]	[redacted]	0.00
2020	[redacted]	[redacted]	0.00
2021	[redacted]	[redacted]	0.00
2022	[redacted]	[redacted]	0.00
2023	[redacted]	[redacted]	0.00
2024	[redacted]	[redacted]	0.00
2025	[redacted]	[redacted]	0.00
2026	[redacted]	[redacted]	0.00
2027	[redacted]	[redacted]	0.00
2028	[redacted]	[redacted]	0.00

High and Low Cost Combination Sensitivities (15-16)

The high and low cost combination sensitivities included a grouping of three individual sensitivities to form a more extreme case. The high cost combination case included the high fuel cost scenario, high construction cost, and high T&D sensitivities, while the low cost combination case included the low fuel cost scenario, low construction cost, and the low T&D sensitivities.

Residential Rate Analysis Sensitivity (17)

Four alternative residential rate designs developed by the Company's rate group are used as model inputs to the Company's load forecasting models. These designs are explained in detail in Section 6.3. The adjustments to peak and energy forecast due to these rate designs are evaluated in this sensitivity. The studies considered are.

- Study A: Flat rates during summer and winter, both distribution and generation are changed;
- Study B: Inclining block rates during summer and winter with flat distribution rates;
- Study C: Flat winter rates with no change in the existing summer rates or existing distribution rates;
- Study D: Increased differential between summer and winter rates for residential customers above the 800 kWh block, i.e., an increase in summer rates and a decrease in winter rates for residential customers using more than 800 kWh per month with no changes to distribution rates.

6.7 INTEGRATED RESOURCE PLAN QUANTITATIVE COMPARISON

The Company examined the six alternative plans using the basecase, three scenarios, and 13 sensitivities to compare and contrast the plans using the NPV utility costs over the Study Period. Figure 6.7.1 presents the results of the alternative plans compared on an individual scenario and sensitivity basis. Each row of the figure constitutes a grouping of plans that were considered for that particular scenario or sensitivity. The results are displayed as a percentage change in costs compared to the Base Plan with basecase assumptions (marked with a star).

Figure 6.7.1 ALTERNATIVE PLAN COMPARISON

Scenarios and Sensitivities		Plan A: Base	Plan B: Fuel Diversity	Plan C: Renewable	Plan D: Coal	Plan E: Climate Action Plan	Plan F: Offshore Wind
1	Base Case	★	10.12%	16.73%	13.06%	14.20%	13.84%
2	No CO2 Cost Scenario	-12.38%	-0.87%	4.90%	0.76%	3.63%	1.81%
3	High Fuel Cost Scenario	8.01%	17.49%	24.60%	21.09%	21.47%	21.79%
4	Low Fuel Cost Scenario	-6.25%	4.44%	10.49%	7.10%	8.00%	7.61%
5	High Load Growth	11.64%	21.83%	28.35%	24.76%	25.80%	25.54%
6	Low Load Growth	-8.53%	1.56%	8.30%	4.54%	5.60%	5.36%
7	High Construction Cost	1.56%	15.58%	22.86%	17.57%	20.53%	18.96%
8	Low Construction Cost	-1.56%	4.66%	10.60%	8.56%	7.88%	8.72%
9	High T&D Costs	-0.08%	10.04%	16.65%	12.98%	14.12%	13.75%
10	Low T&D Costs	0.08%	10.20%	16.81%	13.15%	14.29%	13.92%
11	Net Metering	-0.14%	9.98%	16.59%	12.93%	14.06%	13.70%
12	Electric Vehicles	2.69%	12.87%	19.42%	15.75%	16.88%	16.56%
13	No REC Sales	0.47%	10.79%	18.00%	13.53%	14.87%	14.92%
14	High REC Sales	-0.50%	9.42%	15.42%	12.56%	13.50%	12.72%
15	High Cost Combination	9.39%	22.76%	30.57%	25.44%	27.57%	26.75%
16	Low Cost Combination	-7.63%	-0.82%	4.53%	2.75%	1.90%	2.66%
17	Residential Rate Analysis						
	A Flat Rate	0.55%	10.72%	17.29%	13.57%	14.74%	14.42%
	B Inclining Block Rates	0.12%	10.28%	16.86%	13.17%	14.34%	13.99%
	C Flat Winter Rate	-0.03%	10.08%	16.70%	13.03%	14.17%	13.80%
	D Summer/Winter Differential Increased	-0.08%	10.02%	16.65%	13.00%	14.11%	13.76%
	Plan Average	-0.14%	10.05%	16.61%	12.96%	14.08%	13.72%

Note: The results are displayed as a percentage of costs compared to the Base Plan with basecase assumptions (marked with star).

6.8 2013 PLAN

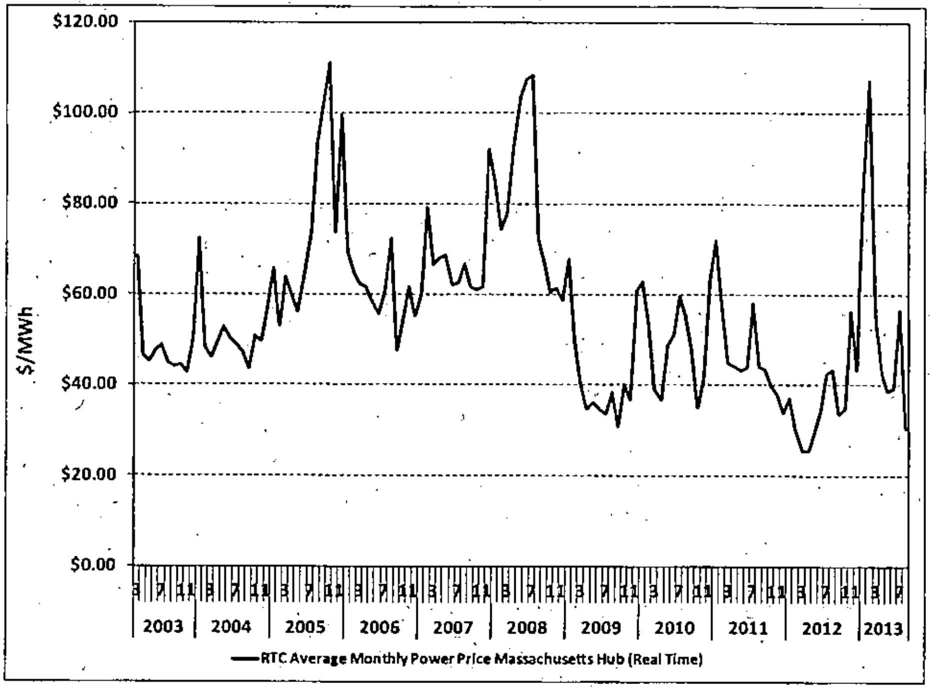
Based on the quantitative analytics and qualitative assessments conducted, the Company recommends a path forward that continues to follow an expansion consistent with Plan A: Base Plan, which follows least-cost methodology given basecase assumptions, and concurrently continues forward with reasonable development efforts of the additional resources identified in Plan B: Fuel Diversity Plan (Plan A and B are specified in Chapter 6). Collectively, this recommended path forward is the 2013 Plan.

As mentioned in earlier Sections of this document, the electric power industry has been and continues to be dynamic in nature with rapidly changing developments and regulatory challenges. The Company expects that these dynamics will continue into the future and will be further complicated by societal megatrends such as an enhanced interest in national security (which includes infrastructure security) and climate change focused laws and regulations. Therefore, it is prudent for the Company to adequately preserve reasonable development options available to it in order to be able to respond to the future market, regulatory, and industry changes that are likely to occur in some form, but are difficult to predict at the present time. This is especially important to preserve resource options requiring significantly longer development timelines such as nuclear and wind.

Consistent with the results of Section 6.7, Plan A: Base Plan, given current basecase assumptions, is the least cost plan and performs reasonably well under the deterministic scenarios and sensitivities included in Section 6.7. Plan A: Base Plan, however, is almost exclusively dependent on fueling the Company's expansion with natural gas. Following this path would potentially leave the Company and its customers vulnerable to natural gas price volatility similar to that seen in the New England States over the last 15 to 20 years (see Figure 6.8.1). In addition, this vulnerability is magnified by possible future regulatory limitations on natural gas production or service disruptions on the natural gas transmission/distribution grid. Such low probability, high impact events could lead to electric service reliability issues and large costs to the Company's customers and the economy of its service territory that could be mitigated by the more resource diverse Plans identified in Section 6.7. While such events are low probability in nature, the electric power industry (along with the United States) has experienced numerous "low probability, high impact" events during recent history. For example:

- Electric power de-regulation and subsequent re-regulation;
- Midwest capacity shortages of the late 1990s and early 2000s;
- California Energy Crisis of the early 2000s;
- EPA's Mercury & Air Toxics Standards leading to massive coal unit retirements;
- High gas prices of the mid-2000s leading to the shale gas revolution;
- Mortgage crisis leading to the recession of 2007 through 2009.

Figure 6.8.1 MASS HUB POWER PRICES



The deterministic scenarios and sensitivities identified in Sections 6.6 and 6.7 are designed to mimic events with a reasonable-to-high probability of occurrence. As described above, however, low probability events do occur. When planning any portfolio, it is fundamental to prepare for uncertainty. For these reasons the Company is recommending Plan A: Base Plan, while concurrently preserving the continued development of the additional resource options included in Plan B: Fuel Diversity Plan.

The Company maintains that the Fuel Diversity Plan, despite its higher cost under current planning assumptions, would promote fuel-price stability for customers over the long-term by reducing an overreliance on any one fuel source and/or generation technology. In addition, the Fuel Diversity Plan includes a more balanced mix of baseload, intermediate, and peaking units, as well as a diverse fuel mixture including fossil, nuclear, and renewable resources. Plan A: Base Plan and Plan B: Fuel Diversity Plan are displayed in tabular format in Figures 6.8.2(a) and 6.8.2(b), respectively.

Figure 6.8.2(a) PLAN A: BASE PLAN

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2014		SPP		BR3 – Gas BR4 – Gas		Approved & Extended DSM
2015	Warren	EEP / SLR NUG SPP / EP&S			CEC 1-4 YT 1-2	Proposed & Future DSM
2016	Brunswick					
2017						
2018			PP5 – SNCR YT3 – SNCR			
2019	CC					
2020						
2021	CT					
2022	CT					
2023	CT					
2024						
2025						
2026						
2027	CC					
2028						

Figure 6.8.2(b) PLAN B: FUEL DIVERSITY PLAN

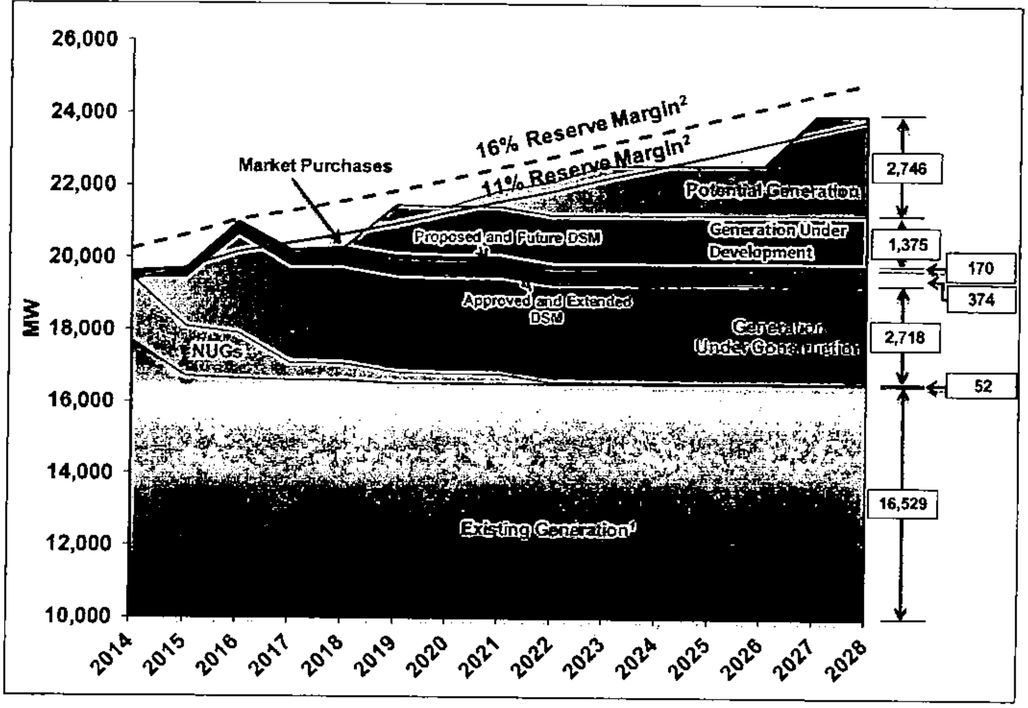
Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Repower	Retire	
2014		SPP		BR3 – Gas BR4 – Gas		Approved & Extended DSM
2015	Warren	EEP / SLR NUG SPP / EP&S			CEC 1-4 YT 1-2	Proposed & Future DSM
2016	Brunswick					
2017		SLR TAG / SLR				
2018		OFFD / SLR	PP5 – SNCR YT3 – SNCR			
2019	CC	SLR				
2020		SLR TAG / SLR				
2021		SLR				
2022	CT	WND				
2023		WND				
2024		WND				
2025	North Anna 3					
2026						
2027	CT					
2028	CT					

***Key:** Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or repower by natural gas; Retire: Remove a unit from service; BR: Bremo; Brunswick: Brunswick County Power Station; CEC: Chesapeake Energy Center Unit; CC: Combined-Cycle; CT: Combustion Turbine (2 units); EEP: Energy Extraction Partners, LLC; EP&S: Economic Power & Steam Generation, LLC; OFFD: Offshore Wind Demonstration Project; North Anna 3: North Anna Unit 3; PP5: Possum Point Unit 5; SNCR: Selective Non-Catalytic Reduction; SLR: Generic Solar; SLR NUG: Solar NUG; SLR TAG: Solar Tag; SPP: Solar Partnership Program; Warren: Warren County Power Station; WND: Onshore Wind; YT: Yorktown Unit*
***Note:** 1) DSM capacity savings continue to increase throughout the Planning Period.*

The Company believes it is prudent to continue reasonable development efforts of the additional resource options identified in Plan B: Fuel Diversity Plan for the following reasons:

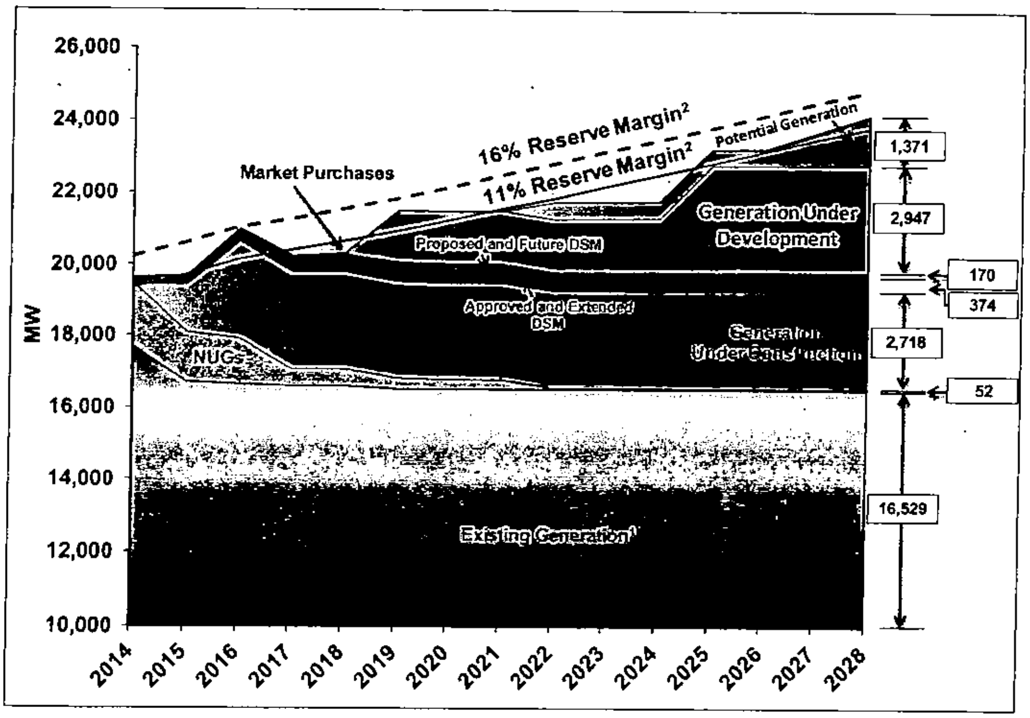
a) while initially capital intensive, nuclear units represent the most cost-effective available large-scale baseload, non-intermittent, near emission-free, and reliable resource for meeting future energy and capacity needs;
b) the Base Plan's potential generation expansion of almost exclusively CC and CT technology is heavily reliant on a single fuel source, natural gas;
c) the need for new nuclear power becomes greater with the future license expirations of the Company's current nuclear facilities. The license expirations of Surry Units 1 (838 MW) and 2 (838 MW) and North Anna Unit 1 (838 MW) occur within the Study Period (2032, 2033, and 2038, respectively). The license for North Anna Unit 2 (835 MW) will also expire in 2040;
d) three land-based wind energy sites in Virginia with a potential to generate a total of 247 MW (nameplate) would support the Company's portfolio fuel diversity and decrease the Company's overall emissions, including CO_2;
e) developing the Offshore Wind Demonstration Project (12 MW nameplate) is a first step towards a potentially viable future renewable resource that enhances fuel diversity and decreases emissions; and
f) approximately 220 MW (nameplate) of new generation powered by solar energy by 2024 (including several new Company-owned PV installations) which would support the Company's portfolio, fuel diversity, and decrease the Company's overall emissions, including CO_2.

Figure 6.8.3(a) PLAN A: BASE PLAN – CAPACITY (2014 - 2028)



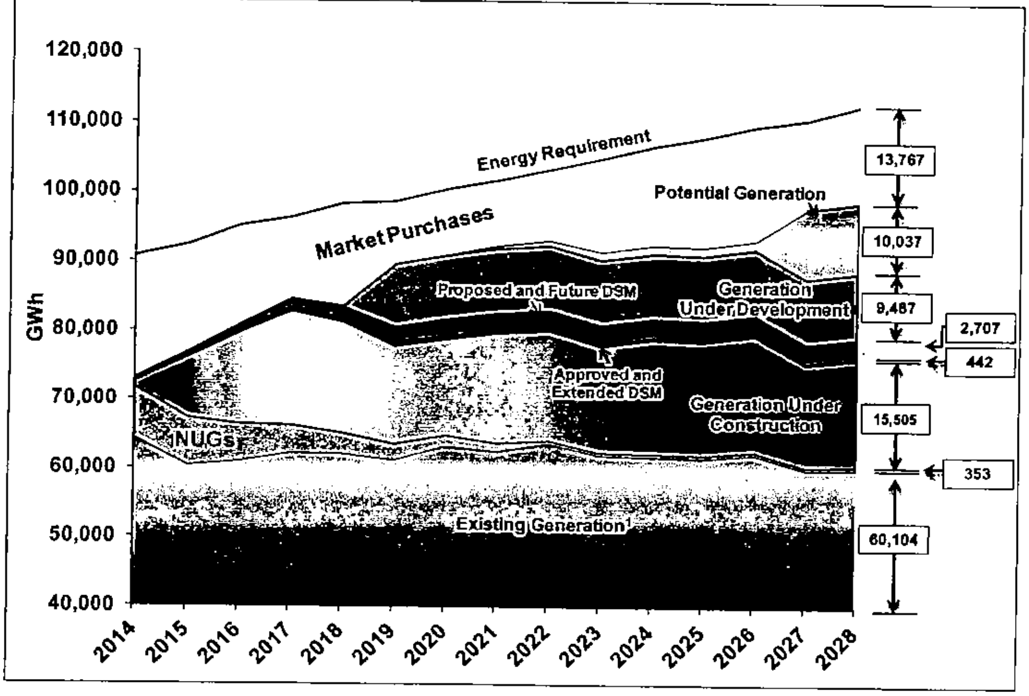
Note: ***1)*** *Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.*
2) *See Section 4.2.2.*

Figure 6.8.3(b) PLAN B: FUEL DIVERSITY PLAN – CAPACITY (2014 - 2028)



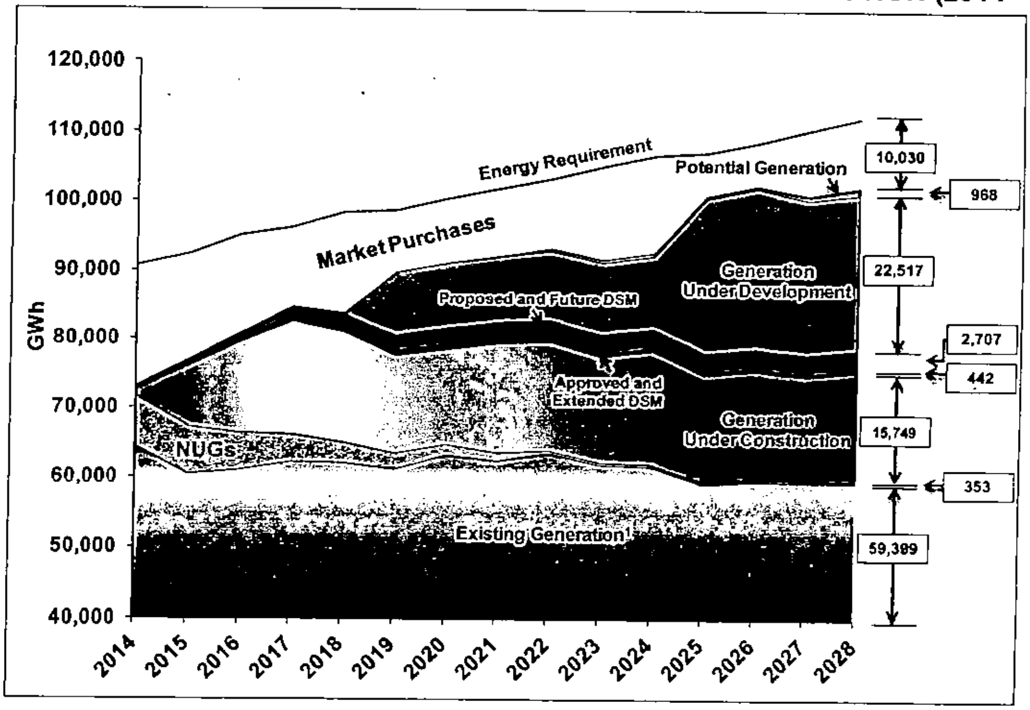
Note: ***1)*** *Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.*
2) *See Section 4.2.2.*

Figure 6.8.4(a) PLAN A: BASE PLAN – ENERGY PROJECTION (2014 – 2028)



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan.

Figure 6.8.4(b) PLAN B: FUEL DIVERSITY PLAN – ENERGY PROJECTION (2014 – 2028)



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan.

In addition to maintaining the balance between baseload, intermediate, and peaking capacity, the Company has considered the fuel mix that would result from its 2013 Plan. Figure 6.8.5 and Figure 6.8.6 display the Company's current fuel mix including uranium, coal, oil, natural gas, renewables, purchased power, and NUGs for the Base Plan and the Fuel Diversity Plan. Figure 6.8.5 displays how the Base Plan meets the energy requirements throughout the Study Period. The Base Plan's generation expansion relies almost exclusively on natural gas units as seen in Figure 6.5.1, and therefore the energy mix throughout the Study Period becomes increasingly dependent on natural gas. Figure 6.8.6 illustrates that the Fuel Diversity Plan helps maintain a more balanced, diverse fuel mix that also continues to include nuclear as a major source of dispatchable baseload energy to reliably meet the increasing energy requirements throughout the Study Period.

Figure 6.8.5 ENERGY BY SOURCE (BASE PLAN)

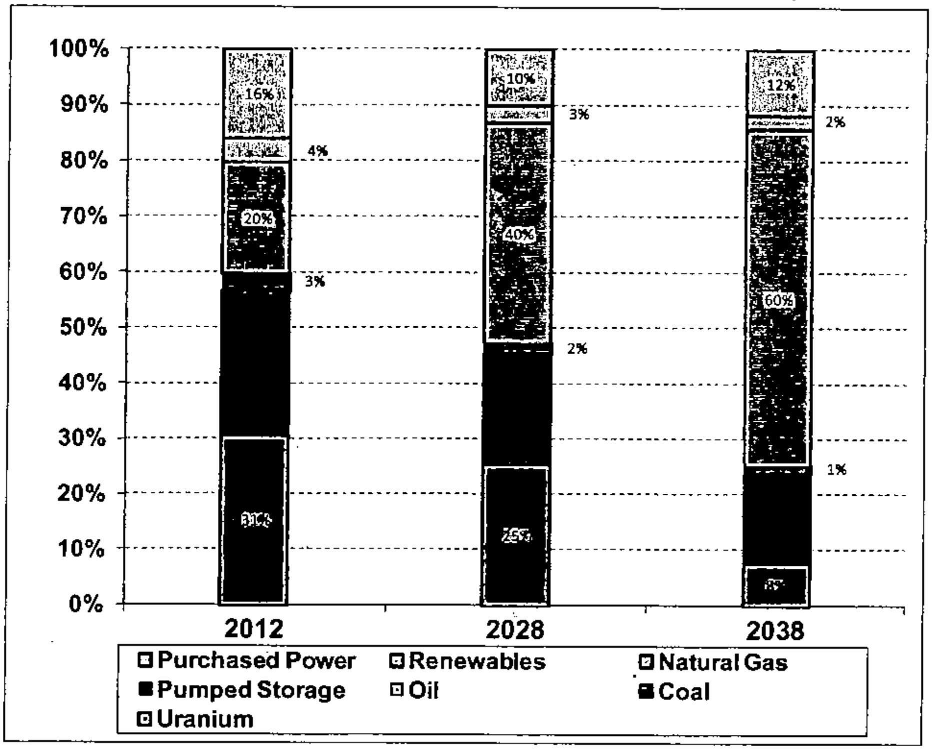
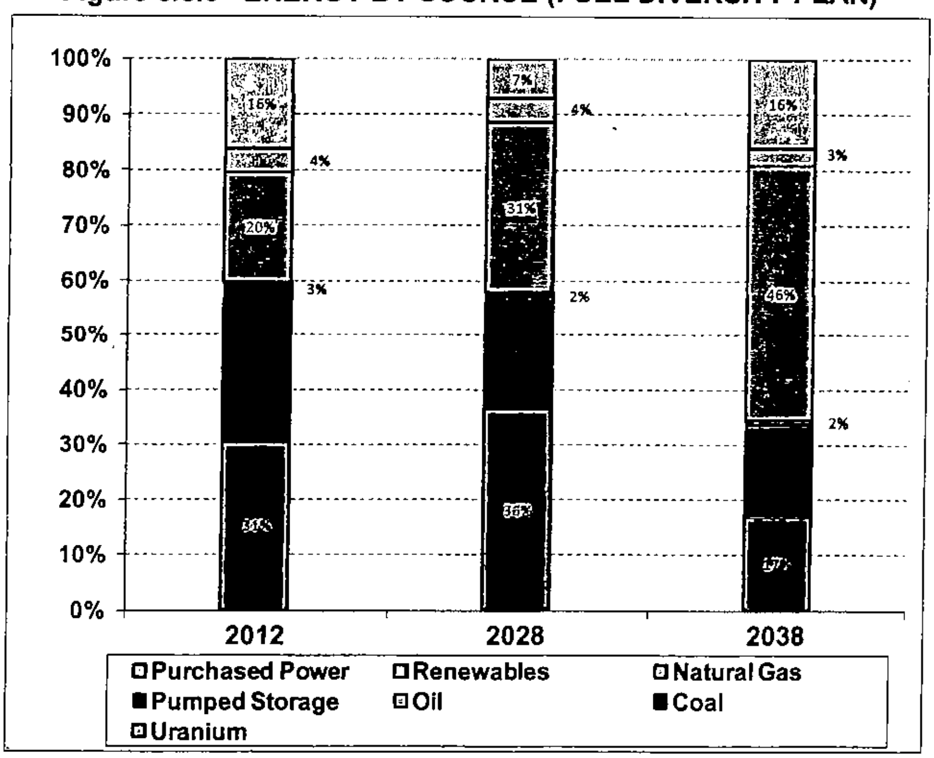


Figure 6.8.6 ENERGY BY SOURCE (FUEL DIVERSITY PLAN)



6.9 CONCLUSIONS

The Company's 2013 Plan provides a recommended path forward to ensure the Company reliably meets its customers' needs for energy and capacity at the lowest reasonable cost. The Company proposes to pursue Plan A: Base Plan, while concurrently continuing reasonable development efforts to preserve the additional resource options identified in Plan B: Fuel Diversity Plan, so that the Company and its customers are well positioned to meet the challenges of an uncertain industry future over the long-term. Figure 6.9.1 summarizes Plan A: Base Plan from 2014 to 2028. Figure 6.9.2 provides the additional resources under development between Plan A: Base Plan and Plan B: Fuel Diversity.

Figure 6.9.1 SUMMARY OF THE 2013 BASE PLAN

Year	Supply-side Resources	
	New Conventional	New Renewable
2014		SPP
2015	Warren	EEP / SLR NUG / SPP / EP&S
2016	Brunswick	
2017		
2018		
2019	CC	
2020		
2021	CT	
2022	CT	
2023	CT	
2024		
2025		
2026		
2027	CC	
2028		

Figure 6.9.2 ADDITIONAL RESOURCES UNDER DEVELOPMENT FROM THE 2013 FUEL DIVERSITY PLAN

Year	Supply-side Resources	
	New Conventional	New Renewable
2014		
2015		
2016		
2017		SLR TAG / SLR
2018		OFFD / SLR
2019		SLR
2020		SLR TAG / SLR
2021		SLR
2022		WND
2023		WND
2024		WND
2025	North Anna 3	
2026		
2027		
2028		

Chapter 7

Short-Term Action Plan

CHAPTER 7 – SHORT-TERM ACTION PLAN

The STAP provides the Company's strategic plan for the next five years (2014 – 2018), as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in this 2013 Plan. A combination of developments on the market, technological, and regulatory fronts over the next five years will likely shape the future of the Company and the utility industry for many decades to come. The Company is proactively positioning itself in the short-term to address these evolving developments for the benefit of all stakeholders over the long-term. Major components of the Company's strategy for the next five years are expected to include:

- enhance and upgrade the Company's existing transmission grid;
- construct additional generation while maintaining a balanced fuel mix;
- avoid overreliance on power imports;
- continue to develop and implement a renewable strategy that supports the Virginia RPS goals and the North Carolina REPS requirements;
- conduct DSM market potential study;
- continue to implement cost-effective DSM programs in Virginia and North Carolina; and
- enhance reliability and customer service.

A more detailed discussion of the current and planned activities over the next five years is provided in the following sections.

7.1 CURRENT ACTIONS (2013)

Demand-Side Management:

Virginia

On August 31, 2012, in Case No. PUE-2012-00100, the Company applied to extend the Residential Air Conditioner Cycling and Low Income Programs in Virginia. Both these programs were approved for extension by the SCC in April 2013. On August 30, 2013, the Company applied for SCC approval of three new DSM Programs (Phase III) as discussed in Chapter 3 (Case No. PUE-2013-00072).

North Carolina

On August 16, 2012, in Docket No. E-22, Subs 467 and 469, the Company received approval to suspend the Commercial HVAC Upgrade and Commercial Lighting Programs. On August 20, 2013, the Company filed for NCUC approval of the Phase II DSM Programs that were approved in Virginia in Case No. PUE-2011-00093, with the exception of the CDG Program, which was previously denied approval in North Carolina. Additionally, in Docket Nos. E-22, Sub 489 and 465, the Company filed for NCUC approval of the Commercial Lighting and Commercial HVAC Programs on a North Carolina-only basis.

Advanced Metering Infrastructure:

The Company is currently installing AMI, or smart meters, on homes and businesses in areas throughout Virginia. AMI has demonstrated the effectiveness of the technology in achieving voltage conservation, remotely turning off and on electric service, power outage and restoration detection and reporting, remote daily meter readings, and offering dynamic rates.

On March 22, 2013, the Company filed a Petition with the SCC in Case No. PUE-2010-00135 for approval to extend, expand and modify the Dynamic Pricing Tariffs Pilot. As explained in the Petition, the Company's request for early approval to extend the term of the Pilot will allow existing participants to continue on the Dynamic Pricing Tariffs, as well as further expand the Pilot by allowing additional customers an opportunity to enroll, as the current enrollment period has ended, including customers who may have become eligible to participate since the initial enrollment period closed November 30, 2012. The matter is currently pending before the SCC.

Conventional Generation:

- Solar Partnership Program 24 MW (nameplate) (30 MW DC) of PV solar DG – is under construction and is expected to be complete by 2015.
- Convert Bremo Units 3 and 4 (227 MW) upon CPCN approval (filed August 31, 2012).
- Warren County Power Station (1,337 MW), approved on February 2, 2012, is currently under construction.
- Brunswick County Power Station (1,375 MW), approved on August 2, 2013, is currently under construction.
- Continue reasonable development efforts associated with the North Anna 3 Nuclear Unit.

Transmission:

Virginia:

The following planned Virginia transmission projects detailed in Figure 7.2.6 are pending SCC approval or are tentatively planned for filing with the SCC in 2013:

- Surry – Skiffes Creek 500 kV Line, Skiffes Creek-Whealton 230 kV Line and 500-230 kV Substation (Case No. PUE-2012-00029) is pending and approval is requested by October 2013.
- Loudoun – Pleasant View 500 kV Line #558 Rebuild.
- Dooms – Lexington 230 kV Line.

Renewable Energy Resources:

Approximately 561 MW of qualifying renewable generation is currently in operation. The Company has existing contracts for approximately 25 MW of BTMG of renewable capacity, as well as one contracted renewable NUG facility at Covanta Fairfax that will provide approximately 63 MW in 2013.

Virginia:

- Virginia RPS Program – The Company plans to meet its 2013 target by applying renewable generation from existing qualified facilities and purchasing cost-effective RECs.
- Virginia Annual Report – On November 1, 2013, the Company intends to submit its Annual Report to the SCC, as required, detailing its efforts towards the RPS plan.
- Altavista biomass conversion achieved commercial operation on July 12, 2013. Hopewell and Southampton (51 MW each) biomass conversions are under construction, and expected to be complete by the end of 2013.

North Carolina:

- North Carolina REPS Compliance Report – The Company achieved its 2013 Solar set-aside and general obligation requirement, which is detailed in its annual REPS Compliance Report submitted on August 29, 2013.
- North Carolina REPS Compliance Plan – The Company submitted its annual REPS Compliance Plan, which is filed as North Carolina IRP Addendum 1 to this 2013 Plan.

7.2 FUTURE ACTIONS (2014 – 2018)

DSM PROGRAMS

Figure 7.2.1 lists the projected demand and energy savings by 2018 from the approved and extended, proposed and future DSM programs.

Figure 7.2.1 DSM PROJECTED SAVINGS BY 2018

Program	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Air Conditioner Cycling Program [2]	174	0	Approved / Approved
Residential Low Income Program [2]	2	10	
Residential Lighting Program	22	276	Completed / Completed
Commercial Lighting Program [1]	15	121	Closed / Suspended
Commercial HVAC Program	1	7	
Non-Residential Distributed Generation Program	55	1	Approved / Rejected
Non-Residential Energy Audit Program	16	96	Approved / Proposed
Non-Residential Duct & Sealing Program	14	65	
Residential Bundle Program	73	231	
Residential Home Energy Check-Up Program	2	9	
Residential Duct & Sealing Program	6	10	
Residential Heat Pump Tune Up Program	44	149	
Residential Heat Pump Upgrade Program	21	62	
Non-Residential Solar Window Film Program	15	66	Proposed / Future
Non-Residential Lighting Systems & Controls Program	53	188	
Non-Residential Heating & Cooling Efficiency Program	7	30	
Voltage Conservation Program	0	1092	Future / Future
Non-Residential Re-Commissioning Program	0	6	
Non-Residential Custom Incentive Program	44	172	
New Residential Low Income Program	2	11	

***Notes:** 1) This program was originally approved as part of the Company's filing in Case No. PUE-2009-00081.*
2) This program represents the extension of the corresponding originally approved program in Case No. PUE-2009-00081.

GENERATION ADDITIONS AND CHANGES:

Figure 7.2.2 lists the generation plants that are currently under construction and are expected to be operational by 2018. Figure 7.2.3 lists the generation plants that are currently under development and are expected to be operational by 2018.

Figure 7.2.2 GENERATION UNDER CONSTRUCTION

Forecasted COD[1]	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW)	
					Summer	Winter
2015	Warren County Power Station	Warren County, VA	Natural Gas	Intermediate/ Baseload	1,337	1,437
2015	Solar Partnership Program	VA	Solar	Intermittent	24[2]	24[2]
2016	Brunswick County Power Station	Brunswick, VA	Natural Gas	Intermediate/ Baseload	1,375	1,509

Note: 1) *Commercial Operation Date.*
2) Solar Partnership Program DC capacity is 30 MW (nameplate) while the figure displays AC capacity.

Figure 7.2.3 GENERATION UNDER DEVELOPMENT[1]

Forecasted COD	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW)	
					Summer	Winter
2017	Solar	VA	Renewable	Intermittent	15	15
2017	Solar Tag	VA	Renewable	Intermittent	4	4
2018	Solar	VA	Renewable	Intermittent	15	15
2018	Offshore Wind Demonstration Project	VA	Wind	Intermitent	2	2

Note: 1) *All Generation Under Development projects and planned capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals .*

GENERATION UPRATES/DERATES:

Figure 7.2.4 lists the Company's planned changes to existing generating units.

Figure 7.2.4 CHANGES TO EXISTING GENERATION

Unit Name	Type	MW	Year Effective
Bremo 3	Conversion	0	2014
Bremo 4	Conversion	0	2014
Possum Point 5	SNCR	0	2018
Yorktown 3	SNCR	0	2018

GENERATION RETIREMENTS:

The Company plans to retire the units listed in Figure 7.2.5.

Figure 7.2.5 GENERATION RETIREMENTS

Unit Name	MW Summer	Year Effective
Chesapeake 1	111	2015
Chesapeake 2	111	2015
Chesapeake 3	156	2015
Chesapeake 4	217	2015
Possum Point CT	72	2015
Yorktown 1	159	2015
Yorktown 2	164	2015
Lowmoor CT	48	2016
Mt. Storm CT	11	2016
Northern Neck CT	48	2017

Transmission:

Figure 7.2.6 lists the major transmission additions including line voltage and capacity, expected operation target dates, and their regulatory status.

Figure 7.2.6 PLANNED TRANSMISSION ADDITIONS

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #65 Uprate (Garner - Lancaster)	115	217	Sep-13	VA
Lexington - Cloverdale Line # 566 Uprate	500	4,000	Dec-13	VA
Line 270 - Burke to Sideburn - Install 2nd UG 230kV Cable	230	586	Mar-14	VA
N 301 Industrial Park 115kV DP (HEMC)	115	261	Apr-14	NC
Hollymead Tap Rebuild	230	1,047	May-14	VA
Dooms to Bremo 230kV Transmission Line Rebuild	115	240	May-14	VA
Dahlgren Substation 230kV Line (Loop Line #2076)	230	1,047	May-14	VA
Line #69 Uprate	115	263	May-14	VA
Line #148 Uprate	115	162	May-14	VA
Glebe-Radnor Heights-Ballston 230kV UG Line	230	354	Jun-14	VA
Line #100 Rebuild between Chesterfield - Harrowgate	115	398	Jun-14	VA
Northwest to Lakeside 230kV Line	230	1,047	Jun-14	VA
Uprate Line #575 (Ladysmith - North Anna)	500	3428	Jun-14	VA
Cannon Branch to Cloverhill - New 230kV Line	230	1,047	Jul-14	VA
Line #80 Rebuild	115	262	Oct-14	NC
Convert Line 64 to 230kV and Install 230kV Capacitor Bank at Winfall	230	775 (#2131) 840(#2126)	Dec-14	NC
Rebuild Line #551 (Mt Storm - Doubs)	500	4,334	Dec-14	VA
Line #296 Reconductor Halifax to Dominion/Progress Dividing Line	230	712	Feb-15	VA/NC
Uprate Line 2022 - Possum Point to Dumfries Substation	230	705	May-15	VA
Line #262 Rebuild (Yadkin - Chesapeake EC) Line #2110 Reconductor (Suffolk - Thrasher)	230 230	1,047 1195	May-15	VA
Shawboro – Aydlett Tap 230kV Line	230	751	May-15	NC
Cloverhill to Liberty - New 230kV Line	230	1,047	May-15	VA
Surry - Skiffes Creek 500 kV Line	500	4,325	May-15	VA
Skiffes Creek - Whealton 230 kV Line	230	1,047	May-15	VA
Line #2020 Rebuild Winfall - Elizabeth City	230	1,047	Jun-15	NC
Yadkin - Chesapeake increase 115 kV Capacity	115	398	Jun-15	VA
Line #22 Rebuild Kerr Dam - Eatons Ferry	115	262	Jun-15	VA/NC
Line #30 Rebuild (Altivista to Skimmer)	115	239	Jun-15	VA
2nd 230kV Line Harrisonburg to Endless Caverns	230	1,047	Jun-15	VA
Line #17 Uprate Shockoe - Northeast and Terminate Line #17 at Northeast	115	231	Jul-15	VA
Line #222 Uprate from Northwest to Southwest	230	706	Jul-15	VA
Line #201 Rebuild	230	1,200	Nov-15	VA
Rebuild Dooms to Lexington 500 kV Line	500	4,000	Dec-15	VA
Burton Switching Station and 115 kV Line to Oakwood	115	233	Dec-15	VA
Line #2090 Uprate	230	1,195	May-16	VA
Line #2032 Uprate (Elmont - Four Rivers)	230	1,195	May-16	VA
Loudoun – Pleasant View Line #558 Rebuild	500	4,000	May-16	VA
Line #2104 Reconductor and Upgrade	230	1,047	May-16	VA
Rebuild Line #2027 (Bremo - Midlothian)	230	1,047	May-16	VA
Line #11 - Rebuild or Reconductor from Gordonsville to Somerset	115	353	May-16	VA
Line #33 Rebuild and Halifax 230kV Ring Bus	115	353	Jun-16	VA
Line #22 Rebuild Carolina - Eatons Ferry	115	262	Jun-16	NC
Line #54 Reconductor Carolina - Woodland	115	306	Jun-16	NC
New 230kV Line Dooms to Lexington	230	1,047	Jun-16	VA
*Network Line 2086 from Warrenton	230	1,047	May-17	VA
*Idylwood to Liberty Crossing – New 230kV Line and Liberty Crossing	230	1,047	May-17	VA
Line #69 Uprate Reams DP to Purdy	115	300	Jun-17	VA
Line #553 (Cunningham to Elmont) Rebuild and Uprate	500	4,000	Dec-17	VA
* Rebuild Line #4 Bremo to Cartersville	115	388	May-18	VA

***Note:** Asterisk reflects planned transmission addition subject to change based on inclusion in future PJM RTEP and/or receipt of applicable regulatory approval(s).*

RENEWABLE RESOURCES:

Virginia:

Figure 7.2.7 lists the Company's future renewable resources within the first five years of the Plan.

- The Base Plan and Fuel Diversity Plan include 109 MW (nameplate) of renewable resources. Plan B: Fuel Diversity Plan also identifies an additional 102 MW (nameplate) of renewable resources to be online by 2018 (Figure 7.2.7). The Company plans to meet its Virginia RPS goals at a reasonable cost and in a prudent manner by:
  - a) application of current renewable generating facilities including NUGs;
  - b) purchase of cost-effective RECs;
  - c) continuation of reasonable development efforts associated with new renewable resources; and
  - d) continuation of reasonable developmental efforts associated with offshore wind.

Figure 7.2.7 FUTURE RENEWABLE RESOURCES

Resource Name	Year	Type	Nameplate Capacity (MW)	Firm Capacity (MW)	Plan
Solar Partnership Program	2014	Distributed Solar	12	3.5	A,B
Solar Partnership Program	2015	Distributed Solar	12	3.5	A,B
Energy Extraction Partners, LLC	2015	Solid Waste	15	15	A,B
Economic Power & Steam Generation, LLC	2015	Biomass/Wood	20	20	A,B
Solar NUG	2015	Solar	50	19	A,B
Solar	2017	Solar	40	15	B
Solar Tag	2017	Solar	10	4	B
Solar	2018	Solar	40	15	B
Offshore Wind Demonstration Project	2018	Wind	12	2	B

***Key:** A: Plan A: Base Plan; B: Plan B: Fuel Diversity.*
***Note:** 1) Solar Partnership Program DC capacity is 30 MW (nameplate) and will be implemented in two phases.*

North Carolina:

- The Company's strategy to meet the North Carolina REPS requirements is outlined in the Company's 2013 REPS Compliance Plan, filed as North Carolina IRP Addendum 1 to this 2013 Plan.
- Solar requirements will be met by purchasing unbundled solar RECs. The Company has procured the solar RECs necessary to comply with the North Carolina REPS solar requirements for 2013.
- The Company continues to develop its plans to comply with swine and poultry waste requirements. The Company intends to meet the general REPS requirements with a combination of:
  - a) energy efficiency programs;
  - b) Company-generated renewable resources;
  - c) purchase of cost-effective RECs; and
  - d) development of new renewable resources when and where feasible.

OTHER INITIATIVES:

As discussed in Section 5.4, the Company is currently pursuing other technologies and resources within the next five years including:

- *Solar Power Partnership and Purchase Programs* - In response to Chapter 771 of the 2011 Virginia Acts of Assembly that promoted solar DG, the Company filed for and received approval for a solar DG demonstration program with two components: the Solar Partnership Program and the Solar Purchase Program. In the Solar Partnership Program, the Company installs solar panels on public and private property at strategic sites in its Virginia service area to study the impact and assess the benefits to the distribution system. The Solar Purchase Program provides the opportunity for customers to sell solar generation output and renewable energy certificates to the Company. The size of the Company's combined components of the solar DG demonstration program, the Solar Partnership Program and the Solar Purchase Program, is not to exceed 33 MW.
- *Rate Schedule RG* - The Company has filed for approval of a demonstration program to offer large non-residential customers in Virginia the ability to purchase a greater percentage of their energy needs from renewable energy resources than they currently receive from the company's existing generation mix. If approved, the Company would provide this offering under Rate Schedule RG, a voluntary companion rate to customers taking service under the GS-3 and GS-4 rates. Rate Schedule RG would allow qualifying non-residential customers to choose the percentage of their energy requirements that they want to meet with renewable resources.
- *EV Pilot Program* - On July 11, 2011, in SCC Case No. PUE-2011-00014, the SCC approved the Company's petition for a pilot program to offer experimental and voluntary EV rate options, providing incentives to residential customers who purchase or lease EVs to charge them during off-peak periods. The program is open to up to 1,500 residential customers, with up to 750 in each of the two experimental rates. Pilot enrollment began October 3, 2011, and the Pilot will conclude on November 30, 2014. If warranted by the results of the Pilot program, the Company plans to request approval of a Virginia service territory EV peak-shaving program in the future.
- *Dynamic Pricing Tariffs Pilot* - In April 2011, the SCC approved a Dynamic Pricing Tariffs Pilot in Case No. PUE-2010-00135. The Company's filing was in response to the SCC's July 30, 2010 Order Establishing Pilot Programs issued in Case No. PUE-2009-00084. The Pilot program offers residential and small commercial AMI customers the option to enroll in a dynamic rate, where the price for electricity varies based on day classification, time of day, and season. If warranted by the results of the Pilot, the Company may seek approval of a Virginia service territory Dynamic Pricing Tariffs Program. On March 22, 2013, the Company filed a Petition with the SCC in Case No. PUE-2010-00135 for approval to extend, expand and modify the Dynamic Pricing Tariffs Pilot. As explained in the Petition, the Company's request for early approval to extend the term of the Pilot will allow existing participants to continue on the Dynamic Pricing Tariffs, as well as further expand the Pilot by allowing additional customers an opportunity to enroll, as the

current enrollment period has ended, including customers who may have become eligible to participate since the initial enrollment period closed November 30, 2012. The matter is currently pending before the SCC.

Appendix

APPENDIX 2A – TOTAL SALES BY CUSTOMER CLASS (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2003	27,246	24,732	10,525	9,445	280	3,074	75,301
2004	28,249	25,878	10,843	9,798	284	2,171	77,223
2005	29,942	27,023	10,331	10,120	280	1,735	79,431
2006	28,544	27,078	10,168	10,040	282	1,841	77,952
2007	30,469	28,416	10,094	10,660	283	1,995	81,917
2008	29,646	28,484	9,779	10,529	282	1,926	80,646
2009	29,904	28,455	8,644	10,448	276	1,909	79,635
2010	32,547	29,233	8,512	10,670	281	1,980	83,223
2011	30,779	28,957	7,960	10,555	273	2,013	80,538
2012	29,174	28,927	7,849	10,496	277	1,947	78,671
2013	31,333	29,994	8,081	10,581	292	1,983	82,264
2014	30,859	32,393	8,317	10,313	304	2,013	84,198
2015	31,190	34,377	8,330	10,356	308	2,016	86,576
2016	31,469	36,361	8,301	10,460	313	2,060	88,964
2017	31,633	37,693	8,203	10,518	318	2,081	90,446
2018	31,857	38,813	8,145	10,473	322	2,110	91,720
2019	32,180	39,723	8,081	10,536	327	2,143	92,989
2020	32,601	40,775	8,035	10,586	331	2,192	94,519
2021	32,899	41,679	7,990	10,596	335	2,225	95,723
2022	33,284	42,667	7,948	10,607	339	2,267	97,111
2023	33,688	43,670	7,917	10,612	342	2,311	98,540
2024	34,204	44,716	7,900	10,639	346	2,365	100,171
2025	34,563	45,574	7,878	10,602	350	2,400	101,367
2026	35,029	46,546	7,855	10,587	353	2,444	102,815
2027	35,485	47,563	7,834	10,555	357	2,489	104,283
2028	36,129	48,597	7,838	10,567	360	2,523	106,014

Note: *Historic (2003 – 2012), Projected (2013 – 2028).*

APPENDIX 2B – VIRGINIA SALES BY CUSTOMER CLASS (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2003	25,822	23,993	8,961	9,303	272	3,074	70,347
2004	26,771	25,109	9,051	9,652	275	2,171	72,984
2005	28,359	26,243	8,621	9,976	272	1,735	75,164
2006	27,067	26,303	8,404	9,903	274	1,841	73,705
2007	28,890	27,606	8,359	10,519	274	1,995	77,556
2008	28,100	27,679	8,064	10,391	273	1,926	76,384
2009	28,325	27,646	7,147	10,312	268	1,909	75,558
2010	30,831	28,408	6,872	10,529	273	1,980	78,842
2011	29,153	28,163	6,342	10,423	265	2,013	76,309
2012	27,672	28,063	6,235	10,370	269	1,947	74,507
2013	29,690	29,176	6,640	10,441	283	1,932	78,162
2014	29,243	31,583	6,831	10,176	295	1,959	80,087
2015	29,558	33,543	6,842	10,219	299	1,961	82,422
2016	29,822	35,502	6,818	10,321	303	2,005	84,772
2017	29,977	36,815	6,738	10,379	308	2,025	86,242
2018	30,189	37,914	6,691	10,334	313	2,053	87,494
2019	30,496	38,811	6,637	10,396	317	2,086	88,743
2020	30,894	39,844	6,600	10,446	321	2,133	90,239
2021	31,177	40,735	6,563	10,456	325	2,166	91,421
2022	31,542	41,706	6,528	10,466	329	2,208	92,779
2023	31,924	42,692	6,503	10,471	332	2,251	94,174
2024	32,413	43,721	6,489	10,498	336	2,304	95,762
2025	32,754	44,567	6,471	10,462	339	2,339	96,931
2026	33,195	45,523	6,452	10,447	343	2,382	98,342
2027	33,627	46,523	6,435	10,415	346	2,427	99,773
2028	34,238	47,539	6,438	10,427	350	2,460	101,451

Note: *Historic (2003 – 2012), Projected (2013 – 2028).*

APPENDIX 2C – NORTH CAROLINA SALES BY CUSTOMER CLASS (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2003	1,424	739	1,564	141	8	1,078	4,954
2004	1,479	769	1,792	146	8	45	4,239
2005	1,583	780	1,709	143	8	43	4,267
2006	1,477	775	1,763	137	8	87	4,247
2007	1,579	810	1,735	140	8	89	4,362
2008	1,546	806	1,715	138	8	49	4,262
2009	1,579	809	1,497	136	8	49	4,078
2010	1,716	825	1,640	141	8	52	4,381
2011	1,626	795	1,618	132	8	51	4,230
2012	1,502	864	1,614	126	8	50	4,165
2013	1,643	818	1,441	140	9	51	4,102
2014	1,616	810	1,486	137	9	54	4,111
2015	1,632	834	1,488	137	9	55	4,154
2016	1,646	859	1,483	139	9	55	4,191
2017	1,655	878	1,465	139	9	56	4,203
2018	1,667	899	1,455	139	9	57	4,226
2019	1,684	913	1,443	140	10	57	4,247
2020	1,706	931	1,435	140	10	58	4,280
2021	1,722	945	1,427	140	10	59	4,302
2022	1,742	961	1,420	141	10	59	4,332
2023	1,764	977	1,414	141	10	60	4,365
2024	1,791	995	1,411	141	10	61	4,408
2025	1,810	1,008	1,407	140	10	61	4,436
2026	1,834	1,023	1,403	140	10	61	4,473
2027	1,858	1,040	1,399	140	10	62	4,510
2028	1,891	1,058	1,400	140	11	63	4,562

Note: *Historic (2003 – 2012), Projected (2013 – 2028).*

APPENDIX 2D – TOTAL CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2003	1,964,320	213,461	709	27,673	2,136	5	2,208,304
2004	1,998,691	216,186	684	27,910	2,275	5	2,245,751
2005	2,036,041	219,837	655	28,233	2,426	5	2,287,197
2006	2,072,726	223,961	635	28,540	2,356	4	2,328,222
2007	2,102,751	227,829	620	28,770	2,347	3	2,362,319
2008	2,124,089	230,715	598	29,008	2,513	3	2,386,925
2009	2,139,604	232,148	581	29,073	2,687	3	2,404,097
2010	2,157,581	232,988	561	29,041	2,798	3	2,422,972
2011	2,171,795	233,760	535	29,104	3,031	3	2,438,227
2012	2,187,670	234,947	514	29,114	3,246	3	2,455,495
2013	2,209,359	236,901	496	28,960	3,498	3	2,479,216
2014	2,237,119	239,490	495	29,077	3,642	3	2,509,825
2015	2,271,014	242,499	493	29,250	3,786	3	2,547,045
2016	2,307,123	245,661	492	29,466	3,930	3	2,586,676
2017	2,342,452	248,779	491	29,686	4,074	3	2,625,484
2018	2,375,281	251,739	490	29,900	4,218	3	2,661,631
2019	2,405,094	254,504	489	30,094	4,362	3	2,694,546
2020	2,433,100	257,148	487	30,235	4,506	3	2,725,479
2021	2,460,206	259,735	486	30,330	4,650	3	2,755,410
2022	2,486,631	262,276	485	30,399	4,794	3	2,784,587
2023	2,512,433	264,777	484	30,451	4,938	3	2,813,086
2024	2,537,620	267,239	483	30,488	5,082	3	2,840,914
2025	2,562,625	269,687	481	30,512	5,226	3	2,868,534
2026	2,587,823	272,147	480	30,526	5,370	3	2,896,350
2027	2,613,075	274,612	479	30,535	5,514	3	2,924,218
2028	2,638,076	277,061	478	30,540	5,658	3	2,951,816

Note: *Historic (2003 – 2012), Projected (2013 – 2028).*

APPENDIX 2E – VIRGINIA CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2003	1,868,437	198,240	630	25,778	1,777	3	2,094,865
2004	1,901,785	200,958	606	26,017	1,913	3	2,131,281
2005	1,937,806	204,457	585	26,343	2,062	3	2,171,255
2006	1,973,430	208,556	566	26,654	1,994	2	2,211,201
2007	2,002,884	212,369	554	26,896	1,971	2	2,244,675
2008	2,023,592	215,212	538	27,141	2,116	2	2,268,601
2009	2,038,843	216,663	522	27,206	2,290	2	2,285,525
2010	2,056,576	217,531	504	27,185	2,404	2	2,304,202
2011	2,070,786	218,341	482	27,252	2,639	2	2,319,502
2012	2,086,647	219,447	464	27,265	2,856	2	2,336,680
2013	2,102,761	220,327	443	27,021	2,973	2	2,353,526
2014	2,129,182	222,734	441	27,130	3,096	2	2,382,585
2015	2,161,441	225,533	440	27,292	3,218	2	2,417,926
2016	2,195,809	228,474	439	27,494	3,340	2	2,455,559
2017	2,229,433	231,373	438	27,698	3,463	2	2,492,408
2018	2,260,678	234,127	437	27,898	3,585	2	2,526,727
2019	2,289,052	236,699	436	28,079	3,707	2	2,557,975
2020	2,315,707	239,158	435	28,210	3,830	2	2,587,342
2021	2,341,505	241,563	434	28,300	3,952	2	2,615,756
2022	2,366,655	243,926	433	28,364	4,075	2	2,643,455
2023	2,391,212	246,253	432	28,412	4,197	2	2,670,508
2024	2,415,185	248,542	431	28,447	4,320	2	2,696,926
2025	2,438,983	250,819	430	28,469	4,442	2	2,723,145
2026	2,462,965	253,107	429	28,483	4,564	2	2,749,550
2027	2,486,998	255,400	427	28,490	4,687	2	2,776,005
2028	2,510,793	257,677	426	28,495	4,809	2	2,802,203

Note: *Historic (2003 – 2012), Projected (2013 – 2028).*

APPENDIX 2F – NORTH CAROLINA CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2003	95,884	15,221	79	1,895	359	2	113,439
2004	96,906	15,228	79	1,894	362	2	114,470
2005	98,235	15,380	70	1,890	364	2	115,942
2006	99,296	15,406	69	1,886	363	2	117,021
2007	99,867	15,460	66	1,874	376	1	117,644
2008	100,497	15,502	60	1,867	397	1	118,324
2009	100,761	15,485	59	1,867	398	1	118,572
2010	101,005	15,457	56	1,857	395	1	118,771
2011	101,009	15,418	53	1,852	392	1	118,725
2012	101,024	15,501	50	1,849	390	1	118,815
2013	106,598	16,574	53	1,939	525	1	125,690
2014	107,937	16,755	53	1,947	546	1	127,240
2015	109,572	16,966	53	1,958	568	1	129,119
2016	111,315	17,187	53	1,973	590	1	131,118
2017	113,019	17,405	53	1,987	611	1	133,077
2018	114,603	17,612	53	2,002	633	1	134,904
2019	116,042	17,806	52	2,015	655	1	136,570
2020	117,393	17,991	52	2,024	676	1	138,137
2021	118,701	18,172	52	2,031	698	1	139,654
2022	119,976	18,349	52	2,035	719	1	141,132
2023	121,221	18,525	52	2,039	741	1	142,578
2024	122,436	18,697	52	2,041	763	1	143,989
2025	123,642	18,868	52	2,043	784	1	145,389
2026	124,858	19,040	52	2,044	806	1	146,800
2027	126,076	19,213	51	2,044	827	1	148,213
2028	127,283	19,384	51	2,045	849	1	149,613

Note: *Historic (2003 – 2012), Projected (2013 – 2028).*

APPENDIX 2G – SUMMER & WINTER PEAKS

Company Name: Virginia Electric and Power Company

POWER SUPPLY DATA

Schedule 5

	(ACTUAL)					(PROJECTED)													
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	16,914	17,638	16,897	17,383	17,811	18,174	18,589	18,131	18,314	18,535	18,816	19,109	19,388	19,678	19,969	20,258	20,554	20,867	21,152
b. Other Commitments(2)	131	117	110	343	568	479	519	-221	-264	-290	-290	-282	-277	-276	-279	-281	-282	-284	-286
c. Total System Summer Peak	16,783	17,521	16,787	17,039	17,244	17,695	18,070	18,351	18,578	18,825	19,106	19,391	19,665	19,955	20,248	20,538	20,836	21,151	21,439
d. Percent Increase in Total Summer Peak	5.4%	4.4%	-4.2%	1.5%	1.2%	2.6%	2.1%	1.6%	1.2%	1.3%	1.5%	1.5%	1.4%	1.5%	1.5%	1.4%	1.4%	1.5%	1.4%
2. Winter																			
a. Adjusted Winter Peak(1)	15,311	15,357	14,654	15,214	15,535	15,607	15,919	16,027	16,108	16,171	16,322	16,531	16,712	16,919	17,108	17,314	17,545	17,782	18,035
b. Other Commitments(2)	127	113	110	120	119	-35	-73	-158	-203	-225	-224	-222	-219	-222	-224	-226	-228	-229	-230
c. Total System Winter Peak	15,184	15,244	14,544	15,093	15,416	15,642	15,992	16,186	16,311	16,396	16,546	16,754	16,931	17,141	17,332	17,540	17,773	18,021	18,266
d. Percent Increase in Total Winter Peak	-1.7%	0.4%	-4.6%	3.8%	2.1%	1.5%	2.2%	1.2%	0.8%	0.5%	0.9%	1.3%	1.1%	1.2%	1.1%	1.2%	1.3%	1.4%	1.4%

(1) Peak after energy efficiency and demand-side programs, includes adjustments from Appendix 2H.
(2) Includes firm commitments for the receipt of specified blocks of power (i.e., unit power, limited term, diversity exchange, etc.).

APPENDIX 2H – PROJECTED SUMMER & WINTER PEAK LOAD & ENERGY FORECAST

Company Name: Virginia Electric and Power Company

Schedule 1

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]				(PROJECTED)														
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,783	17,521	16,787	17,039	17,244	17,695	18,070	18,351	18,578	18,825	19,106	19,391	19,665	19,955	20,248	20,538	20,836	21,151	21,439
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-19	-33	-40	-48	-69	-113	-172	-221	-264	-290	-290	-282	-277	-276	-279	-281	-282	-284	-286
3. Demand Response[(2)(5)]	-14	-42	-65	-101	-129	-151	-175	-203	-228	-240	-243	-244	-245	-247	-249	-252	-254	-256	-259
4. Demand Response-Existing[(2)(3)]	-8	-7	-7	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Peak Adjustment	-	-	-	241	487	592	691	-	-	-	-	-	-	-	-	-	-	-	-
6. Adjusted Load	16,914	17,638	16,897	17,383	17,811	18,174	18,589	18,131	18,314	18,535	18,818	19,109	19,388	19,678	19,969	20,258	20,554	20,867	21,152
7. % Increase in Adjusted Load (from previous year)	5.3%	4.3%	-4.2%	2.9%	2.5%	2.0%	2.3%	-2.5%	1.0%	1.2%	1.5%	1.6%	1.5%	1.5%	1.5%	1.4%	1.5%	1.5%	1.4%
B. Winter																			
1a. Base Forecast	15,184	15,244	14,544	15,093	15,416	15,642	15,992	16,186	16,311	16,396	16,548	16,754	16,931	17,141	17,332	17,540	17,773	18,021	18,266
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-23	-37	-40	-29	-30	-35	-73	-158	-203	-225	-224	-222	-219	-222	-224	-226	-228	-229	-230
3. Demand Response[(2)(4)]	-	-	-14	-26	-34	-37	-41	-49	-55	-58	-59	-60	-61	-62	-63	-64	-65	-66	-67
4. Demand Response-Existing[(2)(3)]	-7	-8	-6	-6	-6	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Adjusted Load	15,311	15,357	14,654	15,214	15,535	15,607	15,919	16,027	16,108	16,171	16,322	16,531	16,712	16,919	17,108	17,314	17,545	17,792	18,035
6. % Increase in Adjusted Load	-1.7%	0.3%	-4.6%	3.8%	2.1%	0.5%	2.0%	0.7%	0.5%	0.4%	0.9%	1.3%	1.1%	1.2%	1.1%	1.2%	1.3%	1.4%	1.4%
2. Energy (GWh)																			
A. Base Forecast	86,656	83,393	81,498	85,044	87,252	89,716	92,190	93,726	95,047	96,362	97,947	99,195	100,633	102,114	103,804	105,044	106,544	108,065	109,859
B. Additional Forecast																			
NCEMC	-	-	-	658	676	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response[5]	-184	-294	-342	-469	-558	-797	-1,234	-1,835	-2,373	-2,845	-3,034	-3,041	-3,080	-3,127	-3,135	-3,140	-3,142	-3,144	-3,149
D. Demand Response-Existing[(2)(3)]	-1	-0.3	-0.4	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
E. Adjusted Energy	86,471	83,099	81,156	85,234	87,370	88,920	90,956	91,891	92,674	93,517	94,913	96,154	97,554	98,887	100,669	101,904	103,402	104,922	106,710
F. % Increase in Adjusted Energy	4.8%	-3.9%	-2.3%	5.0%	2.5%	1.8%	2.3%	1.0%	0.9%	0.9%	1.5%	1.3%	1.5%	1.5%	1.7%	1.2%	1.5%	1.5%	1.7%

(1) Actual metered data.
(2) Demand response programs are classified as capacity resources and are not included in adjusted load.
(3) Existing DSM programs are included in the load forecast.
(4) Values for 2010, 2011 and 2012 represent modeled energy; actual historical data based upon measured and verified EM&V results is not yet available.
(5) Values for 2010, 2011 and 2012 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. Reserve Margin(1)																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW(1)	3,397	3,240	4,668	2,771	3,144	3,080	2,930	2,025	2,045	2,445	2,121	2,287	2,248	2,416	2,230	2,262	2,295	2,611	2,362
b. Percent of Load	20.1%	18.4%	27.7%	15.9%	17.6%	16.9%	15.8%	11.2%	11.2%	13.2%	11.3%	12.0%	11.6%	12.3%	11.2%	11.2%	11.2%	12.5%	11.2%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	12.76%	10.35%	8.53%	13.01%	11.58%	10.85%	15.83%	13.87%	14.49%	14.05%	14.70%	13.05%	11.46%	9.87%	14.83%	13.29%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	7,120	6,544	5,670	6,186	6,005	4,933	6,313	5,957	6,166	6,226	6,482	6,294	6,089	5,858	7,121	6,878
b. Percent of Load	N/A	N/A	N/A	46.8%	42.1%	36.3%	38.9%	37.5%	30.6%	39.0%	36.5%	37.3%	37.3%	38.3%	36.8%	35.2%	33.4%	40.0%	38.1%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin(1)(2)																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW(1)	3,323	3,135	4,778	2,771	3,144	3,080	2,930	2,025	2,045	2,445	2,121	2,287	2,248	2,416	2,230	2,262	2,295	2,611	2,362
b. Percent of Load	19.6%	17.8%	28.4%	15.9%	17.6%	16.9%	15.8%	11.2%	11.2%	13.2%	11.3%	12.0%	11.6%	12.3%	11.2%	11.2%	11.2%	12.5%	11.2%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	12.76%	10.35%	8.53%	13.01%	11.58%	10.85%	15.83%	13.87%	14.49%	14.05%	14.70%	13.05%	11.46%	9.87%	14.83%	13.29%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	7,120	6,544	5,670	6,186	6,005	4,933	6,313	5,957	6,166	6,226	6,482	6,294	6,089	5,858	7,121	6,878
b. Percent of Load	N/A	N/A	N/A	46.8%	42.1%	36.3%	38.9%	37.5%	30.6%	39.0%	36.5%	37.3%	37.3%	38.3%	36.8%	35.2%	33.4%	40.0%	38.1%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.
(2) The Company and PJM forecast a summer peak throughout the Planning Period.
(3) Does not include spot purchases of capacity.
(4) The Company follows PJM reserve requirements which are based on LOLE.

CONFIDENTIAL INFORMATION REDACTED

APPENDIX 2J – Economic Assumptions Used In the Load Forecast Models (Annual Growth Rate)

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Population: Total, (Ths.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Disposable Personal Income, (Mil. 05$, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
per Capita Real Disposable Personal Income, (Ths. 05$, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Residential Permits: Total, (#, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Total Manufacturing, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Total Government, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Military personnel, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: State and local government, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Commercial Sector, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Product: Manufacturing, (Mil. Chained 2005 $, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross State Product: Total, (Bil. Chained 2005 $, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Product: State & Local Government, (Mil. Chained 2005 $, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: Economy.com April 2013 vintage

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	CAGR
Population: Total, (Ths.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Disposable Personal Income, (Mil. 05$, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
per Capita Real Disposable Personal Income, (Ths. 05$, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Residential Permits: Total, (#, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Total Manufacturing, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Total Government, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Military personnel, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: State and local government, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Employment: Commercial Sector, (Ths., SA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Product: Manufacturing, (Mil. Chained 2005 $, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross State Product: Total, (Bil. Chained 2005 $, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Product: State & Local Government, (Mil. Chained 2005 $, SAAR)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: Economy.com April 2012 vintage

APPENDIX 3A – EXISTING GENERATION UNITS IN SERVICE

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Altavista	Altavista, VA	Base	Renewable	Feb-1992	51	51
Bath County Units 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,802	1,802
Bear Garden Combined Cycle	Buckingham County, Va	Intermediate	Natural Gas-CC	May-2011	590	622
Bellemeade Combined Cycle	Richmond, VA	Intermediate	Natural Gas-CC	Mar-1991	267	267
Bremo 3	Bremo Bluff, VA	Base	Coal	Jun-1950	71	74
Bremo 4	Bremo Bluff, VA	Base	Coal	Aug-1958	156	161
Chesapeake 1	Chesapeake, VA	Base	Coal	Jun-1953	111	111
Chesapeake 2	Chesapeake, VA	Base	Coal	Dec-1954	111	111
Chesapeake 3	Chesapeake, VA	Base	Coal	Jun-1959	156	162
Chesapeake 4	Chesapeake, VA	Base	Coal	May-1962	217	221
Chesapeake CT 1, 2, 4, 6	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	51	69
Chesterfield 3	Chester, VA	Base	Coal	Dec-1952	98	102
Chesterfield 4	Chester, VA	Base	Coal	Jun-1960	163	168
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	336	342
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	670	690
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197	226
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	200	236
Clover 1	Clover, VA	Base	Coal	Oct-1995	216	218
Clover 2	Clover, VA	Base	Coal	Mar-1996	217	219
Cushaw Hydro Unit	Big Island, VA	Intermediate	Hydro-Conventional	Jan-1930	2	4
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	98
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	97
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	95
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	97
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	121
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	120
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	124
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	135
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	133
Gravel Neck 1-2	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28	38
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	85	98
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	97
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	98
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85	97
Hopewell	Hopewell, VA	Base	Renewable	Jul-1989	51	51
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161	183
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160	183
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160	183
Lowmoor CT 1-4	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48	65

(1) Commercial Operation Date.

APPENDIX 3A Cont. – EXISTING GENERATION UNITS IN SERVICE

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Mecklenburg 1	Clarksville, VA	Base	Coal	Nov-1992	69	69
Mecklenburg 2	Clarksville, VA	Base	Coal	Nov-1992	69	69
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	554	569
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	555	570
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	520	537
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11	15
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	838	868
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834	863
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1	1
Northern Neck CT 1-4	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47	70
Possum Point 3	Dumfries, VA	Peak	Natural Gas	Jun-1955	96	100
Possum Point 4	Dumfries, VA	Peak	Natural Gas	Apr-1962	220	225
Possum Point 5	Dumfries, VA	Peak	Heavy Fuel Oil	Jun-1975	786	805
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	559	615
Possum Point CT 1-6	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72	106
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153	187
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151	187
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	187
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	188
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95	95
Rosemary CC	Roanoke Rapids, NC	Intermediate	Natural Gas-CC	Dec-1990	165	186
Pittsylvania	Hurt, VA	Base	Renewable	Jun-1994	83	83
Solar Partnership Program	Distributed	Intermittent	Renewable	Jan-2012	1	3
Southampton	Franklin, VA	Base	Renewable	Mar-1992	51	51
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	838	875
Surry 2	Surry, VA	Base	Nuclear	May-1973	838	875
Virginia City Hybrid Energy Center	Virginia City, Va	Base	Coal	Jul-2012	600	614
Yorktown 1	Yorktown, VA	Base	Coal	Jul-1957	159	162
Yorktown 2	Yorktown, VA	Base	Coal	Jan-1959	164	165
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	818	820
Subtotal - Base					8,796	9,050
Subtotal - Intermediate					4,316	4,542
Subtotal - Peak					4,592	5,119
Subtotal - Intermittent					1	3
Total					17,705	18,714

(1) Commercial Operation Date.

APPENDIX 3B – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units							
Spruance Genco, Facility 1 (Richmond 1)	Richmond, VA	Base	Coal	115,500	Yes	8/1/1992	7/31/2017
Spruance Genco, Facility 2 (Richmond 2)	Richmond, VA	Base	Coal	85,000	Yes	8/1/1992	7/31/2017
Edgecombe Genco (Rocky Mount)	Battleboro, NC	Base	Coal	115,500	Yes	10/15/1990	10/14/2015
Doswell Complex	Ashland, VA	Intermediate	Natural Gas	604,998	Yes	5/16/1992	5/5/2017
Hopewell Cogen	Hopewell, VA	Intermediate	Natural Gas	336,600	Yes	8/1/1990	7/30/2015
Covanta Fairfax	Lorton, VA	Base	MSW	63,000	Yes	5/5/1990	5/31/2015
Roanoke Valley II	Weldon, NC	Base	Coal	44,000	Yes	6/1/1995	5/31/2020
Roanoke Valley Project	Weldon, NC	Base	Coal	165,000	Yes	5/29/1994	5/28/2019
SEI Birchwood	King George, VA	Base	Coal	217,800	Yes	11/15/1996	11/14/2021
Behind-The-Meter Generation (BTMG) Units(2)							
BTM Alexandria/Arlington - Covanta	VA	NUG	MSW	21,000	No	1/29/1988	1/28/2023
BTM Richmond Electric	VA	Must Take	Methane	2,900	No	8/27/1993	8/26/2013
BTM Brasfield Dam	VA	Must Take	Hydro	2,485	No	10/12/1993	10/11/2013
BTM Suffolk Landfill	VA	Must Take	Methane	3,000	No	11/4/1994	11/3/2014
BTM Columbia Mills	VA	Must Take	Hydro	147	No	2/7/1985	2/6/2015
BTM Schoolfield Dam	VA	Must Take	Hydro	2,500	No	12/1/1990	11/30/2015
BTM Lakeview (Swift Creek) Dam	VA	Must Take	Hydro	400	No	11/26/2008	Auto renew
BTM MeadWestvaco (formerly Westvaco)	VA	NUG	Coal/Biomass	70,000	No	11/3/1982	Auto renew
BTM Banister Dam	VA	Must Take	Hydro	1,785	No	9/28/2008	Auto renew
BTM 4113 Lindberg Ave	NC	Must Take	Solar	2	No	2/19/2008	Auto renew
BTM Coquina Beach	NC	Must Take	Wind	2	No	8/22/2006	Auto renew
BTM Jockey's Ridge State Park	NC	Must Take	Wind	10	No	5/21/2010	Auto renew
BTM 302 First Flight Run	NC	Must Take	Solar	3	No	5/5/2010	Auto renew
BTM 1210 Ocean Trail	NC	Must Take	Wind	2	No	9/4/2008	Auto renew
BTM 146 Turner Road	NC	Must Take	Solar	2	No	7/1/2009	Auto renew
BTM 3620 Virginia Dare Trail N	NC	Must Take	Solar	4	No	9/14/2009	Auto renew
BTM Weyerhaeuser/Domtar	NC	NUG	Coal/biomass	28400(3)	No	7/27/1991	Auto renew
BTM Chapman Dam	VA	Must Take	Hydro	300	No	10/17/1984	Auto renew
BTM Smurfit-Stone Container	VA	NUG	Coal/biomass	48400(4)	No	3/21/1981	Auto renew
BTM Rivanna	VA	Must Take	Hydro	100	No	4/21/1998	Auto renew
BTM Rapidan Mill	VA	Must Take	Hydro	100	No	6/15/2009	Auto renew
BTM River Farm Energy	VA	Must Take	Solar	8	No	1/30/2009	Auto renew
BTM South Hill Renewable Energy	VA	Must Take	Hydro	40	No	11/3/2010	Auto renew
BTM Dairy Energy	VA	Must Take	Biomass	400	No	8/2/2011	8/1/2016
BTM W. E. Partners II	NC	Must Take	Biomass	300	No	3/15/2012	3/14/2017
BTM Plymouth Solar	NC	Must Take	Solar	5,000	No	10/4/2012	10/3/2027
BTM W. E. Partners 1	NC	Must Take	Biomass	100	No	4/26/2013	4/25/2017

(1) Commercial Operation Date.

(2) These units are provided for informational purposes, they are not part of the 2012 Plan.

(3) Agreement to provide excess energy only.

(4) PPA is for Excess Energy only typically 4,000 - 14,000 kW.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company — Schedule 14b

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[5]							
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	25000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	Natural Gas	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A

(5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company — Schedule 14b

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[5]							
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	VA Beach	Standby	Diesel	3500	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/ Natural Gas	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	Natural Gas	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	Natural Gas	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	Natural Gas	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	Natural Gas	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Fairfax County	Standby	Diesel	-	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A
	Charlottesville	Standby	Diesel	400	No	N/A	N/A

5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

APPENDIX 3B Cont. - OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company | Schedule 14b

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[5]							
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black Liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Natural Gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A

(5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company — Schedule 14b

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned(5)							
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Ashburn	Standby	Diesel	22000	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	NG	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	Va Beach	Standby	Diesel	3500	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/NG	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	NG	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	NG	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A

(5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company

Schedule 14b

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned(5)							
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	Natural Gas	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	Natural Gas	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Fairfax County	Standby	Diesel	--	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	New port New's	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black Liquor/Natural Gas	112500	No	N/A	N/A

(5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company — Schedule 14b

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[5]							
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Nat gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Norfolk	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Norfolk	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Newport News	Standby	Diesel	750	No	N/A	N/A
	Chesterfield	Standby	Coal	500	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Richmond Metro	Standby	NG	25000	No	N/A	N/A
	Suffolk	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	21000	No	N/A	N/A
	Richmond	Standby	Diesel	500	No	N/A	N/A
	Hampton Roads	Standby	Diesel	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	12000	No	N/A	N/A
	West Point	Standby	Unknown	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	100	No	N/A	N/A
	Herndon	Standby	Diesel	18100	No	N/A	N/A
	VA	Merchant	RDF	60000	No	N/A	N/A
	Stafford	Standby	Diesel	3000	No	N/A	N/A
	Chesterfield	Standby	Diesel	750	No	N/A	N/A
	Henrico	Standby	Diesel	750	No	N/A	N/A
	Richmond	Standby	Diesel	5150	No	N/A	N/A
	Culpepper	Standby	Diesel	7000	No	N/A	N/A
	Richmond	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Northern VA	Standby	NG	50000	No	N/A	N/A

(5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[5]							
	Hampton Roads	Standby	Diesel	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	12000	No	N/A	N/A
	West Point	Standby	Unknown	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	100	No	N/A	N/A
	Herndon	Standby	Diesel	18100	No	N/A	N/A
	VA	Merchant	RDF	60000	No	N/A	N/A
	Stafford	Standby	Diesel	3000	No	N/A	N/A
	Chesterfield	Standby	Diesel	750	No	N/A	N/A
	Henrico	Standby	Diesel	750	No	N/A	N/A
	Richmond	Standby	Diesel	6150	No	N/A	N/A
	Culpepper	Standby	Diesel	7000	No	N/A	N/A
	Richmond	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	600	No	N/A	N/A
	Northern VA	Standby	NG	50000	No	N/A	N/A
	Hampton Roads	Standby	Unknown	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	13000	No	N/A	N/A
	Southside VA	Standby	Water	227000	No	N/A	N/A
	Northern VA	Standby	Diesel	300	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	30	No	N/A	N/A
	Newport News	Standby	Diesel	1000	No	N/A	N/A
	Hampton	Standby	Diesel	12000	No	N/A	N/A
	Newport News	Standby	Natural gas	3000	No	N/A	N/A
	Newport News	Standby	Diesel	2000	No	N/A	N/A
	Petersburg	Standby	Diesel	1750	No	N/A	N/A
	Various	Standby	Diesel	3000	No	N/A	N/A
	Various	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	16000	No	N/A	N/A
	Northern VA	Standby	Diesel	6450	No	N/A	N/A
	Virginia Beach	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	12 - 2000	No	N/A	N/A
	Innsbrook-Richmond	Standby	Diesel	6050	No	N/A	N/A
	Northern VA	Standby	Diesel	150	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Virginia Beach	Standby	Diesel	1500	No	N/A	N/A
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	30000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A

(5) These units are provided for informational purposes, they are not part of the 2013 Plan.

APPENDIX 3C – EQUIVALENT AVAILABILITY FACTOR (%)

Company Name: Virginia Electric and Power Company

Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2010 (ACTUAL)	2011	2012	2013 (PROJECTED)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Altavista	85	-	-	53	[illegible]	94	82	84	[illegible]	94	82	94	92	94	[illegible]	94	82	94	92
Bath County Units 1-6	[illegible]	84	86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Bear Garden CC	-	[illegible]	87	90	73	90	90	84	82	90	90	[illegible]	90	90	90	82	90	90	90
Bellemeade CC	81	82	84	[illegible]	84	87	85	87	88	90	90	84	84	90	90	90	90	90	[illegible]
Bremo 3	87	[illegible]	86	-	83	93	90	90	90	90	90	90	90	90	90	90	90	90	90
Bremo 4	77	84	83	-	[illegible]	82	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Brunswick County CC	-	-	-	-	-	-	57	90	90	90	73	90	90	84	90	90	90	90	90
Chesapeake 1	[illegible]	85	90	92	84	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	[illegible]	[illegible]	91	92	84	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	78	83	86	87	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	70	[illegible]	91	87	[illegible]	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 2, 4, 6	92	80	75	88	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	[illegible]	88	41	83	87	81	87	87	87	87	87	87	87	87	87	87	87	87	87
Chesterfield 4	81	86	90	82	85	[illegible]	86	86	86	85	85	85	85	85	85	85	85	86	85
Chesterfield 5	78	83	86	79	83	79	83	82	83	82	83	82	83	82	83	82	83	82	93
Chesterfield 6	87	84	74	88	78	88	76	85	80	86	[illegible]	[illegible]	86	[illegible]	[illegible]	[illegible]	86	[illegible]	86
Chesterfield 7 CC	77	92	87	95	[illegible]	97	93	97	78	97	[illegible]	85	[illegible]	89	87	91	[illegible]	91	89
Chesterfield 8 CC	87	91	73	95	[illegible]	89	97	88	78	97	91	85	97	93	89	97	86	89	98
Clover 1	94	96	79	98	98	88	93	96	80	95	98	[illegible]	96	96	86	95	98	88	98
Clover 2	95	[illegible]	84	95	83	96	[illegible]	[illegible]	90	96	[illegible]	84	98	[illegible]	96	95	96	96	98
Covanta Fairfax	89	[illegible]	82	70	91	85	-	-	-	-	-	-	-	-	-	-	-	-	-
Cushaw Hydro	42	31	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Darbytown 1	98	98	94	94	94	87	94	90	92	92	92	92	92	92	92	92	92	92	92
Darbytown 2	98	[illegible]	97	94	94	87	94	90	92	92	92	93	92	92	92	[illegible]	92	92	92
Darbytown 3	98	[illegible]	87	84	84	87	94	90	82	[illegible]	[illegible]	92	[illegible]	92	92	92	[illegible]	92	92
Darbytown 4	79	98	98	84	94	87	94	87	92	92	92	92	92	92	92	92	92	92	[illegible]
Doswell Complex	81	84	88	71	84	84	84	95	-	-	-	-	-	-	-	-	-	-	-
Economic Power & Steam Generation	-	-	-	-	-	85	85	85	85	86	85	85	85	85	[illegible]	85	86	86	85
Edgecombe Genco (Rocky Mountain)	95	99	98	89	90	95	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	83	[illegible]	98	[illegible]	90	94	94	87	90	80	90	80	90	90	90	90	90	90	90
Elizabeth River 2	87	87	[illegible]	89	84	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 3	82	96	[illegible]	89	90	94	87	90	90	90	90	90	90	90	90	90	90	90	90
Energy Extraction Partners	-	-	-	-	-	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Gaston Hydro	89	79	88	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Generic CC 3x1 2019	-	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Generic CC 3x1 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	[illegible]
Generic CT 2021	-	-	-	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Generic CT 2022	-	-	-	-	-	-	-	-	-	-	-	-	[illegible]	88	88	[illegible]	88	88	[illegible]
Generic CT 2023	-	-	-	-	-	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gordonsville 1 CC	[illegible]	[illegible]	82	85	87	87	87	87	84	[illegible]	87	[illegible]	91	97	91	91	87	91	91
Gordonsville 2 CC	71	83	87	[illegible]	84	89	97	[illegible]	87	91	97	91	87	84	91	97	94	91	97
Gravel Neck 1-2	87	84	93	[illegible]	88	88	[illegible]	[illegible]	83	[illegible]	-	-	-	-	-	-	-	-	-
Gravel Neck 3	98	93	97	41	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Gravel Neck 4	98	73	97	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Gravel Neck 5	79	97	92	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Gravel Neck 6	98	92	72	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Hopewell	91	85	87	32	92	[illegible]	92	84	92	92	92	92	92	92	92	92	92	92	92
Hopewell Cogen	90	86	88	82	81	94	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	87	[illegible]	95	83	90	90	90	90	90	90	90	90	90	90	90	90	90	82	89
Ladysmith 2	93	[illegible]	84	81	90	90	90	90	90	90	90	90	90	90	90	90	90	89	89
Ladysmith 3	98	91	94	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	89
Ladysmith 4	98	92	96	80	90	90	90	90	90	90	90	90	90	90	90	90	90	80	89
Ladysmith 5	99	92	98	90	90	90	90	90	90	90	90	90	90	90	90	90	90	80	94
Lowmoor CT 1-4	99	100	98	[illegible]	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-	-	-	-

APPENDIX 3C Cont. – EQUIVALENT AVAILABILITY FACTOR (%)

Company Name: Virginia Electric and Power Company

Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2010 (ACTUAL)	2011	2012	2013	2014 (PROJECTED)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Mecklenburg 1	84	[illegible]	84	95	90	82	[illegible]	82	81	81	92	85	[illegible]	95	91	95	91	90	85
Mecklenburg 2	84	98	94	95	91	95	95	92	81	81	95	91	[illegible]	92	96	91	95	91	90
Mount Storm 1	[illegible]	82	87	77	87	79	83	87	[illegible]	81	87	87	87	87	87	87	87	87	81
Mount Storm 2	87	76	80	82	[illegible]	84	80	84	[illegible]	[illegible]	[illegible]	88	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	88	[illegible]
Mount Storm 3	81	83	[illegible]	[illegible]	[illegible]	83	84	90	82	[illegible]	89	[illegible]	[illegible]	89	[illegible]	89	[illegible]	89	[illegible]
Mount Storm CT	86	87	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	84	77	85	90	[illegible]	92	91	98	91	91	98	91	91	98	91	91	98	91	91
North Anna 2	79	74	98	89	91	98	91	91	98	91	91	98	91	91	98	91	91	98	91
North Anna Hydro	-	-	-	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Northern Neck CT 1-4	86	90	89	[illegible]	[illegible]	89	[illegible]	88	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania 1	[illegible]	81	79	80	91	93	91	91	90	90	91	91	91	91	91	91	91	91	91
Possum Point 3	83	79	87	85	83	91	87	87	91	91	92	91	91	91	87	91	91	91	92
Possum Point 4	43	87	83	91	85	91	86	91	91	91	87	91	91	91	85	91	91	91	87
Possum Point 5	78	75	77	78	57	85	[illegible]	77	78	85	78	85	69	85	78	85	78	85	69
Possum Point 6 CC	86	78	90	88	89	82	89	87	82	89	88	89	89	82	89	89	89	89	89
Possum Point CT 1-6	96	90	98	96	89	[illegible]	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	95	82	[illegible]	87	85	90	90	90	90	90	90	90	90	90	90	90	90	90	88
Remington 2	87	87	[illegible]	87	90	87	90	90	90	90	90	90	90	90	90	90	90	90	[illegible]
Remington 3	87	87	87	87	90	90	87	90	90	90	90	90	90	90	90	90	90	90	89
Remington 4	88	84	[illegible]	87	[illegible]	90	90	90	90	90	90	90	90	90	90	90	90	90	89
Roanoke Rapids Hydro	97	84	93	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Roanoke Valley II	[illegible]	85	89	89	89	88	89	89	[illegible]	89	87	-	-	-	-	-	-	-	-
Roanoke Valley Project	[illegible]	[illegible]	80	67	84	87	87	87	67	85	-	-	-	-	-	-	-	-	-
Rosemary CC	80	[illegible]	86	86	87	[illegible]	87	91	87	97	97	97	97	91	97	97	91	97	87
SEI Birchwood	93	78	91	86	87	87	82	87	87	87	87	82	-	-	-	-	-	-	-
Solar NUG 2015	-	-	-	-	-	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Solar Partnership Program	-	-	-	13	18	21	27	27	27	27	27	27	27	27	27	27	27	27	31
Southampton	89	90	85	16	[illegible]	94	94	94	94	94	94	94	94	94	[illegible]	94	94	94	94
Spruance Genco, Facility 1 (Richmond 1)	89	84	86	84	90	90	90	96	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	96	81	84	83	[illegible]	[illegible]	[illegible]	86	-	-	-	-	-	-	-	-	-	-	-
Surry 1	87	[illegible]	90	89	98	91	91	98	91	91	98	91	91	[illegible]	91	91	98	91	91
Surry 2	98	78	90	96	91	92	98	91	91	98	91	91	98	91	91	98	91	91	98
Virginia City	-	-	80	84	84	84	84	84	86	81	82	86	84	92	88	84	82	85	84
Warren County CC	-	-	-	-	87	90	90	90	90	82	87	87	97	[illegible]	97	97	87	85	97
Yorktown 1	84	73	72	84	[illegible]	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	78	73	78	87	93	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	80	54	67	81	57	81	73	79	78	85	78	85	78	85	78	85	78	85	78

APPENDIX 3D – NET CAPACITY FACTOR

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA
Net Capacity Factor (%)

	(ACTUAL)								(PROJECTED)										
Unit Name	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Altavista	34.8	-	-	63.4	85.2	93.8	92.2	93.8	91.8	93.8	92.2	93.8	91.9	93.8	92.2	93.8	91.9	93.8	92.2
Bath County Units 1-6	16.4	16.2	15.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Bear Garden CC	-	84.4	78.2	76.4	54.6	62.2	55.7	48.2	43.8	44.0	44.1	44.9	45.6	50.8	60.6	47.2	50.7	47.5	45.4
Bellemeade CC	32.1	72.2	62.0	18.7	14.2	13.0	14.8	12.8	13.7	12.4	12.8	13.1	14.8	16.2	15.8	17.0	16.0	14.1	15.1
Bremo 3	37.1	18.2	9.8	-	3.2	4.6	4.2	4.2	4.3	4.2	4.6	3.6	3.2	2.4	2.7	2.9	2.9	2.8	3.0
Bremo 4	55.2	51.8	21.2	-	8.7	9.5	9.6	8.9	10.3	9.4	10.1	11.6	13.2	14.6	14.6	16.2	14.8	13.6	13.5
Brunswick County CC	-	-	-	-	-	-	42.7	71.1	70.0	84.7	52.2	87.2	87.3	83.8	89.5	89.1	89.6	86.0	85.9
Chesapeake 1	82.4	38.0	14.3	30.1	23.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	84.7	38.8	20.4	31.4	23.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	85.0	80.0	56.5	67.2	57.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	88.0	83.1	17.8	83.0	56.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 2, 4, 6	0.4	0.2	0.1	0.6	0.6	0.4	0.4	0.4	0.0	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	38.0	16.5	8.8	16.0	10.6	16.2	17.8	18.6	21.7	20.1	20.3	23.6	26.6	23.1	22.8	23.6	23.7	21.1	21.0
Chesterfield 4	60.4	44.3	18.0	34.6	25.6	23.1	26.1	28.0	31.1	29.1	29.7	31.8	37.6	30.4	30.7	31.8	31.1	27.0	29.1
Chesterfield 5	73.4	39.2	51.8	48.1	43.0	32.8	41.8	39.3	51.4	42.0	40.1	43.3	54.1	41.1	44.9	41.8	47.1	37.8	43.2
Chesterfield 6	81.0	69.8	30.7	58.9	41.0	40.9	41.6	47.8	54.6	48.7	52.7	65.1	57.0	47.7	48.0	50.4	48.7	44.8	46.3
Chesterfield 7 CC	90.0	74.7	85.8	71.0	56.3	57.7	48.1	40.8	30.1	39.8	37.8	37.9	38.7	43.0	44.4	41.6	42.5	37.4	38.8
Chesterfield 8 CC	72.3	64.9	73.8	74.1	80.7	67.1	55.6	42.7	32.4	42.8	38.2	34.6	44.7	43.2	45.9	47.6	44.4	41.9	38.9
Clover 1	81.0	71.4	52.4	78.1	63.2	60.7	72.1	71.7	71.0	76.4	78.8	73.2	83.5	74.3	68.9	73.2	73.2	64.6	71.4
Clover 2	82.1	64.9	62.8	60.0	58.8	69.7	74.6	68.2	80.2	77.3	81.4	81.4	84.5	69.2	75.7	76.7	74.3	78.2	73.2
Covanta Fairfax	108.9	114.6	104.9	67.8	73.7	32.2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cushaw Hydro	57.6	27.7	48.6	41.5	41.6	41.6	41.6	41.6	41.6	41.5	41.6	41.6	41.5	41.6	41.5	41.6	41.5	41.5	41.5
Darbytown 1	6.4	3.4	4.3	3.0	2.7	2.7	2.3	2.6	2.6	2.0	2.0	2.4	2.2	1.8	1.8	1.9	1.8	1.9	2.0
Darbytown 2	6.2	2.9	3.2	4.6	3.0	2.9	2.7	3.1	2.6	2.6	3.0	2.7	2.4	1.8	2.0	2.1	2.0	2.1	2.2
Darbytown 3	6.2	2.8	3.4	4.2	2.9	2.6	2.5	2.9	2.7	2.7	2.8	2.5	2.3	1.7	1.9	2.0	1.9	2.0	2.1
Darbytown 4	5.8	3.3	4.4	3.4	2.6	2.3	2.2	2.6	2.4	2.4	2.4	2.3	2.1	1.5	1.7	1.8	1.7	1.8	1.9
Doswell Complex	41.1	48.8	60.8	37.8	31.6	30.2	25.0	8.8	-	-	-	-	-	-	-	-	-	-	-
Economic Power & Steam Generation	-	-	-	-	-	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Edgecombe Genco (Rocky Mountain)	82.2	42.1	12.0	67.8	66.4	52.7	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	6.8	6.3	4.5	2.5	1.8	1.7	1.6	1.6	1.6	1.7	1.7	1.8	1.4	1.3	1.5	1.8	1.5	1.6	1.7
Elizabeth River 2	8.5	4.4	3.3	2.9	2.0	1.7	1.5	1.8	1.7	1.8	1.8	1.7	1.6	1.4	1.6	1.8	1.6	1.7	1.8
Elizabeth River 3	7.0	4.6	4.9	2.4	1.8	1.6	1.4	1.8	1.5	1.6	1.6	1.6	1.3	1.0	1.2	1.3	1.3	1.6	1.8
Energy Extraction Partners	-	-	-	-	-	70.7	85.2	85.0	85.0	84.9	85.2	84.3	85.0	84.8	85.2	85.0	84.9	85.0	84.5
Gaston Hydro	17.7	10.4	4.8	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Generic CC 3x1 2019	-	-	-	-	-	-	-	-	-	71.3	72.2	72.6	73.5	74.1	74.0	74.3	74.8	74.4	75.4
Generic CC 3x1 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70.1	71.0
Generic CT 2021	-	-	-	-	-	-	-	-	-	-	-	6.7	6.8	6.3	6.8	6.9	7.1	6.9	6.9
Generic CT 2022	-	-	-	-	-	-	-	-	-	-	-	-	9.4	8.7	9.2	9.3	9.5	9.0	9.0
Generic CT 2023	-	-	-	-	-	-	-	-	-	-	-	-	-	11.6	12.1	12.2	12.4	11.8	11.4
Gordonsville 1 CC	38.6	48.6	69.5	54.0	38.5	36.8	35.1	28.7	29.5	23.8	25.4	23.1	28.5	31.1	28.5	28.4	29.6	24.3	25.7
Gordonsville 2 CC	29.3	31.1	66.2	80.3	38.0	32.3	36.8	26.8	28.8	18.8	22.4	23.6	24.6	25.7	28.1	27.1	24.4	23.8	23.2
Gravel Neck 1-2	0.1	0.1	0.1	1.9	1.6	1.4	1.2	1.4	1.3	0.4	-	-	-	-	-	-	-	-	-
Gravel Neck 3	4.8	1.7	0.9	1.6	2.1	2.0	1.7	2.0	1.9	2.0	2.0	1.8	1.8	1.0	1.1	1.1	1.1	1.2	1.3
Gravel Neck 4	5.7	2.0	4.1	3.0	2.4	2.4	2.0	2.6	2.3	2.4	2.4	2.2	2.0	1.2	1.4	1.6	1.4	1.4	1.5
Gravel Neck 5	3.0	3.7	3.8	2.8	2.3	2.3	1.8	2.3	2.1	2.2	2.2	2.1	1.9	1.2	1.2	1.3	1.3	1.4	1.4
Gravel Neck 6	5.1	1.6	0.4	2.6	2.2	2.1	1.8	2.2	2.0	2.1	2.1	2.0	1.7	1.1	1.2	1.2	1.2	1.3	1.3
Hopewell	30.6	12.1	4.5	32.9	91.9	88.2	92.2	93.8	92.2	92.2	92.4	92.2	92.2	92.2	92.4	92.2	92.2	92.2	92.3
Hopewell Cogen	36.4	31.9	40.0	31.1	27.7	16.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	13.3	5.9	8.4	8.6	4.8	6.1	4.6	6.3	5.3	4.9	5.3	4.8	5.5	3.1	3.5	4.4	3.5	3.5	3.6
Ladysmith 2	12.0	6.0	7.9	7.3	5.8	6.8	6.2	6.0	6.1	5.7	6.2	5.4	6.4	3.6	3.9	4.9	4.0	4.0	4.1
Ladysmith 3	14.3	5.8	8.8	8.9	6.5	8.9	8.3	7.4	7.4	8.8	7.2	6.8	7.5	5.8	5.7	6.1	4.9	4.8	5.0
Ladysmith 4	13.6	8.0	8.3	8.6	6.3	6.5	6.9	7.0	7.0	6.5	6.9	6.8	7.2	5.2	4.8	5.7	4.7	4.7	4.8
Ladysmith 5	11.0	8.7	9.1	8.0	5.7	6.0	6.4	6.4	6.3	5.9	6.3	6.0	6.8	4.7	4.2	5.3	4.2	4.3	4.5
Lowmoor CT 1-4	0.0	0.0	0.1	0.6	0.6	0.6	0.1	-	-	-	-	-	-	-	-	-	-	-	-

APPENDIX 3D Cont. – NET CAPACITY FACTOR

Company Name: Virginia Electric and Power Company

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Schedule 8

Unit Name	(ACTUAL) 2010	2011	2012	2013	(PROJECTED) 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Mecklenburg 1	41.0	19.4	18.2	27.3	18.5	18.0	25.2	24.3	26.0	25.3	29.8	33.8	38.4	30.9	29.0	32.3	30.0	25.0	27.8
Mecklenburg 2	39.4	16.5	12.0	24.8	18.1	17.8	22.7	22.3	26.6	24.4	27.3	31.0	36.5	27.3	28.1	26.8	28.9	25.5	24.8
Mount Storm 1	74.1	70.9	75.4	85.0	71.8	65.6	73.9	78.3	80.6	73.7	78.2	78.5	80.7	73.2	73.1	72.2	70.9	70.8	70.6
Mount Storm 2	72.1	54.8	69.5	74.4	71.1	74.5	75.0	78.4	83.0	82.8	83.0	82.7	83.8	76.8	78.4	78.2	77.2	78.5	78.7
Mount Storm 3	81.7	64.4	37.3	72.9	65.2	69.3	57.4	81.4	73.6	79.3	79.9	80.9	80.7	69.6	72.2	70.9	68.4	65.8	64.4
Mount Storm CT	0.1	0.1	0.1	0.0	0.0	0.4	0.1	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	84.3	77.2	87.9	80.4	90.0	92.1	90.8	98.0	90.5	90.5	98.3	90.5	90.5	98.0	90.8	90.5	98.0	90.5	90.8
North Anna 2	79.7	75.6	98.4	89.1	90.5	98.0	90.8	90.5	98.0	90.6	90.8	98.0	90.5	90.5	98.3	90.5	90.5	98.0	90.8
North Anna Hydro	-	-	-	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.8	26.6	26.8
Northern Neck CT 1-4	0.3	0.1	0.1	0.7	0.7	0.5	0.4	0.1	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania 1	59.8	54.0	46.8	47.1	41.8	41.1	63.7	77.5	79.8	81.4	84.4	84.8	86.9	88.8	89.0	89.3	89.0	89.4	88.8
Possum Point 3	12.4	3.1	8.4	12.5	10.0	10.9	10.8	11.2	11.7	10.3	10.6	12.7	14.5	15.8	15.4	16.8	18.1	14.7	14.0
Possum Point 4	11.0	5.6	6.0	10.1	11.5	12.8	12.9	13.0	14.5	11.8	11.1	13.8	15.9	17.2	16.4	18.0	17.4	15.6	14.8
Possum Point 5	5.7	1.0	1.0	1.2	0.8	0.8	0.7	0.7	0.7	0.8	0.8	0.6	0.5	0.4	0.5	0.5	0.5	0.5	0.6
Possum Point 6 CC	63.6	57.5	79.5	68.1	58.6	48.3	48.0	41.0	37.6	35.5	38.3	38.8	38.0	35.7	41.4	41.5	40.2	38.2	37.8
Possum Point CT 1-6	0.0	0.0	0.1	0.6	0.6	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	9.3	5.5	8.1	6.6	4.4	4.5	4.2	4.9	4.7	4.6	4.9	4.2	3.7	2.8	3.1	3.3	3.2	3.3	3.2
Remington 2	8.0	4.8	6.4	4.9	3.5	3.4	3.1	3.8	3.5	3.4	3.6	3.2	2.9	2.1	2.4	2.5	2.4	2.5	2.8
Remington 3	6.0	5.0	5.4	5.2	4.0	4.1	3.5	4.4	4.2	4.1	4.3	3.9	3.4	2.6	2.8	3.0	2.9	3.0	3.0
Remington 4	8.4	6.9	4.6	4.9	3.7	3.6	3.4	4.0	3.6	3.7	4.0	3.5	3.1	2.3	2.8	2.7	2.8	2.8	2.8
Roanoke Rapids Hydro	40.2	22.6	19.4	34.9	34.9	34.9	34.8	34.9	34.9	34.9	34.8	34.9	34.9	34.9	34.9	34.9	34.8	34.8	34.9
Roanoke Valley II	84.8	81.8	86.5	89.0	88.4	85.6	89.3	89.0	89.0	88.1	40.1	-	-	-	-	-	-	-	-
Roanoke Valley Project	88.6	86.5	78.1	88.1	82.6	85.9	87.0	88.5	86.4	38.1	-	-	-	-	-	-	-	-	-
Rosemary CC	6.3	10.6	6.2	18.0	14.9	15.2	19.1	15.2	19.6	14.2	14.8	18.6	19.0	18.4	20.3	21.3	18.8	18.4	18.2
SEI Birchwood	38.1	24.1	19.3	58.2	48.8	50.2	48.1	48.1	53.5	53.4	54.7	42.7	-	-	-	-	-	-	-
Solar NUG 2015	-	-	-	-	-	14.4	14.5	14.4	14.4	14.4	14.5	14.4	14.4	14.4	14.5	14.4	14.4	14.4	14.5
Solar Partnership Program	-	-	-	12.9	17.8	21.4	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1	30.7
Southampton	31.7	17.0	6.6	17.1	86.2	93.8	94.0	93.8	93.8	93.8	94.0	93.8	93.8	93.8	88.4	93.8	93.8	93.8	94.6
Spruance Genco, Facility 1 (Richmond 1)	65.8	55.0	11.7	83.8	58.5	57.0	67.8	32.4	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	64.1	44.9	11.4	65.4	61.7	61.3	68.0	35.0	-	-	-	-	-	-	-	-	-	-	-
Surry 1	87.7	90.5	91.5	88.6	98.0	90.6	90.8	98.0	90.5	90.6	98.3	90.5	90.5	98.0	90.8	90.5	98.0	90.5	90.8
Surry 2	98.6	78.7	90.5	98.0	90.5	92.1	98.3	90.5	90.5	98.0	90.8	90.5	98.0	90.5	90.8	98.0	90.5	90.5	98.3
Virginia City	-	-	42.8	79.9	76.0	74.7	77.1	77.6	82.3	77.2	88.9	84.3	82.0	88.0	83.8	80.5	87.9	87.8	79.8
Warren County CC	-	-	-	-	6.2	72.8	84.7	61.6	58.0	49.7	58.5	61.0	61.1	61.4	64.8	64.4	65.9	54.5	59.5
Yorktown 1	48.9	41.3	17.6	30.1	15.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	58.9	45.1	28.5	44.2	24.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	4.5	2.5	1.3	1.4	1.4	1.2	1.4	1.3	1.4	1.6	1.5	1.3	0.9	0.8	0.8	1.0	0.9	1.0	1.0

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 3E – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10a

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Maximum)

	(ACTUAL)		(PROJECTED)																
Unit Name	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Altavista	12.49	12.48	[redacted]																
Bath County Units 1-6	N/A	N/A																	
Bear Garden CC	-	-																	
Bellemeade CC	9.00	9.00																	
Bremo 3	12.65	12.66																	
Bremo 4	10.60	10.50																	
Brunswick County CC	-	-																	
Chesapeake 1	10.48	10.48																	
Chesapeake 2	10.60	10.60																	
Chesapeake 3	10.31	10.31																	
Chesapeake 4	10.40	10.40																	
Chesapeake CT 1, 2, 4, 6	19.66	19.66																	
Chesterfield 3	11.79	11.79																	
Chesterfield 4	10.61	10.61																	
Chesterfield 5	10.19	10.19																	
Chesterfield 6	10.01	10.01																	
Chesterfield 7 CC	7.33	7.33																	
Chesterfield 8 CC	7.59	7.69																	
Clover 1	9.98	9.98																	
Clover 2	9.81	9.81																	
Covanta Fairfax	10.00	10.00																	
Cushaw Hydro	N/A	N/A																	
Darbytown 1	12.77	12.77																	
Darbytown 2	12.67	12.67																	
Darbytown 3	12.73	12.73																	
Darbytown 4	12.60	12.60																	
Doswell Complex	10.00	10.00																	
Economic Power & Steam Generation	-	-																	
Edgecombe Genco (Rocky Mountain)	10.00	10.00																	
Elizabeth River 1	12.21	12.21																	
Elizabeth River 2	12.32	12.32																	
Elizabeth River 3	12.12	12.12																	
Energy Extraction Partners	-	-																	
Gaston Hydro	N/A	N/A																	
Generic CC 3x1 2019	-	-																	
Generic CC 3x1 2027	-	-																	
Generic CT 2021	-	-																	
Generic CT 2022	-	-																	
Generic CT 2023	-	-																	
Gordonsville 1 CC	8.31	8.31																	
Gordonsville 2 CC	8.23	8.23																	
Gravel Neck 1-2	18.33	18.33																	
Gravel Neck 3	12.62	12.82																	
Gravel Neck 4	13.21	13.21																	
Gravel Neck 5	13.11	13.11																	
Gravel Neck 6	12.05	12.06																	
Hopewell	11.85	11.86																	
Hopewell Cogen	10.00	10.00																	
Ladysmith 1	10.86	10.86																	
Ladysmith 2	10.63	10.63																	
Ladysmith 3	10.51	10.51																	
Ladysmith 4	10.53	10.63																	
Ladysmith 5	10.44	10.44																	
Lowmoor CT 1-4	19.68	19.68																	

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED
APPENDIX 3E Cont. – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10a

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Maximum)

Unit Name	2010 (ACTUAL)	2011 (ACTUAL)	2012 (PROJECTED)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Mecklenburg 1	11.59	11.69	[redacted]																
Mecklenburg 2	11.88	11.86																	
Mount Storm 1	10.07	10.07																	
Mount Storm 2	9.90	9.90																	
Mount Storm 3	10.23	10.23																	
Mount Storm CT	18.87	18.87																	
North Anna 1	10.74	10.74																	
North Anna 2	10.82	10.82																	
North Anna Hydro	N/A	N/A																	
Northern Neck CT 1-4	10.51	10.61																	
Pittsylvania 1	15.63	15.63																	
Possum Point 3	11.47	11.47																	
Possum Point 4	11.09	11.09																	
Possum Point 5	11.03	11.03																	
Possum Point 6 CC	7.17	7.17																	
Possum Point CT 1-6	10.69	10.69																	
Remington 1	10.56	10.56																	
Remington 2	10.69	10.69																	
Remington 3	10.60	10.60																	
Remington 4	10.65	10.65																	
Roanoke Rapids Hydro	N/A	N/A																	
Roanoke Valley II	10.00	10.00																	
Roanoke Valley Project	10.00	10.00																	
Rosemary CC	8.74	8.74																	
SEI Birchwood	10.00	10.00																	
Solar NUG 2015	N/A	N/A																	
Solar Partnership Program	N/A	N/A																	
Southampton	11.62	11.62																	
Spruance Genco, Facility 1 (Richmond 1)	10.00	10.00																	
Spruance Genco, Facility 2 (Richmond 2)	10.00	10.00																	
Surry 1	10.73	10.73																	
Surry 2	10.78	10.78																	
Virginia City	-	-																	
Warren County CC	-	-																	
Yorktown 1	10.49	10.49																	
Yorktown 2	9.90	9.90																	
Yorktown 3	11.11	11.11																	

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED
APPENDIX 3E Cont. – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10b

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Minimum)

Unit Name	2010 (ACTUAL)	2011	2012 (PROJECTED)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Altavista	N/A	N/A	[redacted]																
Bath County Units 1-6	N/A	N/A																	
Bear Garden CC	N/A	N/A																	
Bellemeade CC	N/A	N/A																	
Bremo 3	N/A	N/A																	
Bremo 4	N/A	N/A																	
Brunswick County CC	N/A	N/A																	
Chesapeake 1	N/A	N/A																	
Chesapeake 2	N/A	N/A																	
Chesapeake 3	N/A	N/A																	
Chesapeake 4	N/A	N/A																	
Chesapeake CT 1, 2, 4, 6	N/A	N/A																	
Chesterfield 3	N/A	N/A																	
Chesterfield 4	N/A	N/A																	
Chesterfield 5	N/A	N/A																	
Chesterfield 6	N/A	N/A																	
Chesterfield 7 CC	N/A	N/A																	
Chesterfield 8 CC	N/A	N/A																	
Clover 1	N/A	N/A																	
Clover 2	N/A	N/A																	
Covanta Fairfax	N/A	N/A																	
Cushaw Hydro	N/A	N/A																	
Darbytown 1	N/A	N/A																	
Darbytown 2	N/A	N/A																	
Darbytown 3	N/A	N/A																	
Darbytown 4	N/A	N/A																	
Doswell Complex	N/A	N/A																	
Economic Power & Steam Generation	N/A	N/A																	
Edgecombe Genco (Rocky Mountain)	N/A	N/A																	
Elizabeth River 1	N/A	N/A																	
Elizabeth River 2	N/A	N/A																	
Elizabeth River 3	N/A	N/A																	
Energy Extraction Partners	N/A	N/A																	
Gaston Hydro	N/A	N/A																	
Generic 3x1 CC 2019	N/A	N/A																	
Generic Double CT 2022	N/A	N/A																	
Generic Double CT 2027	N/A	N/A																	
Generic Double CT 2028	N/A	N/A																	
Gordonsville 1 CC	N/A	N/A																	
Gordonsville 2 CC	N/A	N/A																	
Gravel Neck 1-2	N/A	N/A																	
Gravel Neck 3	N/A	N/A																	
Gravel Neck 4	N/A	N/A																	
Gravel Neck 5	N/A	N/A																	
Gravel Neck 6	N/A	N/A																	
Hopewell	N/A	N/A																	
Hopewell Cogen	N/A	N/A																	
Ladysmith 1	N/A	N/A																	
Ladysmith 2	N/A	N/A																	
Ladysmith 3	N/A	N/A																	
Ladysmith 4	N/A	N/A																	
Ladysmith 5	N/A	N/A																	
Lowmoor CT 1-4	N/A	N/A																	

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 3E Cont. – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10b

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Minimum)

Unit Name	2010 (ACTUAL)	2011 (ACTUAL)	2012	2013	2014 (PROJECTED)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Mecklenburg 1	N/A	N/A	[redacted]																
Mecklenburg 2	N/A	N/A	[redacted]																
Mount Storm 1	N/A	N/A	[redacted]																
Mount Storm 2	N/A	N/A	[redacted]																
Mount Storm 3	N/A	N/A	[redacted]																
Mount Storm CT	N/A	N/A	[redacted]																
North Anna 1	N/A	N/A	[redacted]																
North Anna 2	N/A	N/A	[redacted]																
North Anna 3	N/A	N/A	[redacted]																
North Anna Hydro	N/A	N/A	[redacted]																
Northern Neck CT 1-4	N/A	N/A	[redacted]																
Off-shore 12 MW Demonstration	N/A	N/A	[redacted]																
Pittsylvania 1	N/A	N/A	[redacted]																
Possum Point 3	N/A	N/A	[redacted]																
Possum Point 4	N/A	N/A	[redacted]																
Possum Point 5	N/A	N/A	[redacted]																
Possum Point 6 CC	N/A	N/A	[redacted]																
Possum Point CT 1-6	N/A	N/A	[redacted]																
Remington 1	N/A	N/A	[redacted]																
Remington 2	N/A	N/A	[redacted]																
Remington 3	N/A	N/A	[redacted]																
Remington 4	N/A	N/A	[redacted]																
Roanoke Rapids Hydro	N/A	N/A	[redacted]																
Roanoke Valley II	N/A	N/A	[redacted]																
Roanoke Valley Project	N/A	N/A	[redacted]																
Rosemary CC	N/A	N/A	[redacted]																
SEI Birchwood	N/A	N/A	[redacted]																
Solar 2017	N/A	N/A	[redacted]																
Solar 2018	N/A	N/A	[redacted]																
Solar 2019	N/A	N/A	[redacted]																
Solar 2020	N/A	N/A	[redacted]																
Solar 2021	N/A	N/A	[redacted]																
Solar NUG 2015	N/A	N/A	[redacted]																
Solar Partnership Program	N/A	N/A	[redacted]																
Solar Tag Along 2017	N/A	N/A	[redacted]																
Solar Tag Along 2020	N/A	N/A	[redacted]																
Southampton	N/A	N/A	[redacted]																
Spruance Genco, Facility 1 (Richmond 1)	N/A	N/A	[redacted]																
Spruance Genco, Facility 2 (Richmond 2)	N/A	N/A	[redacted]																
Surry 1	N/A	N/A	[redacted]																
Surry 2	N/A	N/A	[redacted]																
Virginia City	N/A	N/A	[redacted]																
Warren County CC	N/A	N/A	[redacted]																
Wind 1	N/A	N/A	[redacted]																
Wind 2	N/A	N/A	[redacted]																
Wind 3	N/A	N/A	[redacted]																
Yorktown 1	N/A	N/A	[redacted]																
Yorktown 2	N/A	N/A	[redacted]																
Yorktown 3	N/A	N/A	[redacted]																

APPENDIX 3F – EXISTING CAPACITY

Company Name: Virginia Electric and Power Company

CAPACITY DATA

Schedule 7

	(ACTUAL)									(PROJECTED)									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. Installed Capacity (MW)[1]																			
a. Nuclear	3,301	3,329	3,362	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349
b. Coal	4,613	4,658	5,248	5,206	4,967	4,037	4,031	4,025	4,019	4,013	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007
c. Heavy Fuel Oil	1,589	1,589	1,589	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604
d. Light Fuel Oil	351	256	256	257	257	185	126	79	79	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	316	316	316	316	543	543	543	543	543	543	543	543	543	543	543	543	543	543	543
f. Natural Gas-Combined Cycle	1,598	2,188	2,187	2,198	2,196	3,533	4,908	4,908	4,908	6,283	6,283	6,283	6,283	6,283	6,283	6,283	6,283	7,658	7,658
g. Natural Gas-Turbine	2,393	2,393	2,393	2,415	2,415	2,415	2,415	2,415	2,415	2,415	2,415	2,872	3,329	3,786	3,786	3,786	3,786	3,786	3,786
h. Hydro-Conventional	317	317	317	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318
i. Pumped Storage	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802
j. Renewable	83	83	83	243	258	273	279	285	291	297	303	303	303	303	303	303	303	303	302
k. Total Company Installed	16,364	16,931	17,553	17,705	17,708	18,058	19,374	19,327	19,327	20,623	20,623	21,080	21,537	21,994	21,994	21,994	21,994	23,369	23,368
l. Other (NUG)	1,749	1,747	1,747	1,747	1,747	1,402	1,286	481	480	315	271	271	53	53	53	53	53	52	52
n. Total	18,113	18,679	19,300	19,453	19,456	19,460	20,660	19,808	19,808	20,938	20,894	21,351	21,590	22,047	22,047	22,047	22,047	23,422	23,420
II. Installed Capacity Mix (%)[2]																			
a. Nuclear	17.7%	17.5%	17.4%	17.2%	17.2%	17.2%	16.2%	16.9%	16.9%	16.0%	16.0%	15.7%	15.5%	15.2%	15.2%	15.2%	15.2%	14.3%	14.3%
b. Coal	25.4%	25.1%	27.2%	26.8%	25.5%	20.7%	19.5%	20.3%	20.3%	19.2%	19.2%	18.8%	18.6%	18.2%	18.2%	18.2%	18.2%	17.1%	17.1%
c. Heavy Fuel Oil	8.9%	8.8%	8.2%	8.2%	8.2%	8.2%	7.8%	8.1%	8.1%	7.7%	7.7%	7.5%	7.4%	7.3%	7.3%	7.3%	7.3%	6.8%	6.8%
d. Light Fuel Oil	1.9%	1.9%	1.3%	1.3%	1.3%	1.0%	0.6%	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Natural Gas-Boiler	1.7%	1.7%	1.6%	1.6%	2.8%	2.8%	2.6%	2.7%	2.7%	2.6%	2.6%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.3%	2.3%
f. Natural Gas-Combined Cycle	8.8%	8.7%	11.3%	11.3%	11.3%	18.2%	23.8%	24.8%	24.8%	30.0%	30.1%	29.4%	29.1%	28.5%	28.5%	28.5%	28.5%	32.7%	32.7%
g. Natural Gas-Turbine	12.3%	13.2%	12.4%	12.4%	12.4%	12.4%	11.7%	12.2%	12.2%	11.5%	11.6%	13.5%	15.4%	17.2%	17.2%	17.2%	17.2%	16.2%	16.2%
h. Hydro-Conventional	1.8%	1.7%	1.6%	1.6%	1.6%	1.6%	1.5%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
i. Pumped Storage	9.7%	9.6%	9.3%	9.3%	9.3%	9.3%	8.7%	9.1%	9.1%	8.6%	8.6%	8.4%	8.3%	8.2%	8.2%	8.2%	8.2%	7.7%	7.7%
j. Renewable	0.5%	0.5%	0.4%	1.3%	1.3%	1.4%	1.4%	1.4%	1.5%	1.4%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%	1.3%
k. Total Company Installed	89.7%	89.8%	90.9%	91.0%	91.0%	92.8%	93.8%	97.6%	97.6%	98.5%	98.7%	98.7%	99.8%	99.8%	99.8%	99.8%	99.8%	99.8%	99.8%
l. Other (NUG)	9.7%	10.2%	9.1%	9.0%	9.0%	7.2%	6.2%	2.4%	2.4%	1.5%	1.3%	1.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
n. Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Net dependable installed capability during peak season.

(2) Each item in Section I as a percent of line n (Total).

APPENDIX 3G – ENERGY GENERATION BY TYPE (GWh)

Company Name: Virginia Electric and Power Company

GENERATION

Schedule 2

	(ACTUAL)			(PROJECTED)															
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. System Output (GWh)																			
a. Nuclear	25,092	24,096	27,186	27,308	28,209	27,860	27,694	28,207	27,618	27,618	28,289	27,618	27,614	28,207	27,700	27,618	28,207	27,618	27,696
b. Coal	27,097	21,831	18,480	26,519	23,547	20,089	21,173	22,837	24,123	23,117	24,420	24,335	25,199	22,712	22,709	22,667	22,694	21,610	21,773
c. Heavy Fuel Oil	707	250	164	179	154	143	147	142	150	168	164	133	101	82	90	101	99	108	116
d. Light Fuel Oil	199	85	74	17.1	16.1	10.7	6.6	5.5	3.2	0.9	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	317	135	180	479	420	501	501	510	551	468	472	561	635	684	667	719	699	638	611
f. Natural Gas-Combined Cycle	6,709	9,152	13,214	11,943	10,289	17,971	21,958	23,875	22,695	29,862	29,558	31,712	32,137	32,154	33,582	33,340	33,730	40,013	40,804
g. Natural Gas-Turbine	1,701	925	1,179	1,097	820	828	741	875	849	819	865	1,139	1,449	1,627	1,720	1,803	1,749	1,702	1,713
h. Hydro-Conventional	1,192	661	580	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
i. Hydro-Pumped Storage	2,911	2,523	2,500	2,369	2,081	1,992	2,202	1,956	2,482	1,693	1,884	1,922	2,039	2,235	2,178	2,281	2,326	1,984	2,024
j. Renewable[1]	413	393	341	849	1,636	1,753	1,984	2,140	2,203	2,242	2,362	2,344	2,340	2,392	2,343	2,358	2,386	2,371	2,342
k. Total Generation	66,338	60,050	63,897	71,357	67,768	71,743	77,003	81,143	81,271	86,584	88,606	90,360	92,110	90,689	91,585	91,484	92,486	96,639	97,676
l. Purchased Power	25,579	28,276	22,633	19,938	22,877	20,307	17,907	14,568	15,233	11,950	11,484	10,914	10,574	13,105	13,538	14,777	15,278	13,764	14,383
m. Total Payback Energy[2]	-	-	-	8	11	13	15	17	19	20	20	20	20	19	21	21	21	20	21
n. Less Pumping Energy	-3,631	-3,151	-3,097	-2,976	-2,615	-2,503	-2,766	-2,457	-3,118	-2,127	-2,366	-2,414	-2,561	-2,808	-2,737	-2,866	-2,922	-2,493	-2,543
o. Less Other Sales[3]	-571	-952	-1,219	-846	-681	-721	-1,300	-1,475	-824	-3,002	-2,923	-2,816	-2,680	-2,110	-1,828	-1,602	-1,551	-3,100	-2,917
p. Total System Firm Energy Req.	87,715	84,223	82,214	87,472	87,370	88,827	90,844	91,779	92,562	93,405	94,801	96,043	97,442	98,875	100,557	101,793	103,291	104,810	106,599
II. Energy Supplied by Competitive Service Providers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Include current estimates for renewable energy generation by VCHEC from 2013 on.
(2) Payback Energy is accounted for in Total Generation.
(3) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

APPENDIX 3H – ACTUAL ENERGY GENERATION BY TYPE (%)

Company Name: Virginia Electric and Power Company

Schedule 3

GENERATION

	(ACTUAL)									(PROJECTED)									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
III. System Output Mix (%)																			
a. Nuclear	28.6%	28.6%	33.1%	31.2%	32.3%	31.4%	30.5%	30.7%	29.8%	29.6%	29.8%	28.8%	28.3%	28.5%	27.5%	27.1%	27.3%	26.4%	26.0%
b. Coal	30.9%	25.9%	22.5%	30.3%	27.0%	22.6%	23.3%	24.9%	26.1%	24.7%	25.8%	25.3%	25.9%	23.0%	22.6%	22.3%	22.0%	20.6%	20.4%
c. Heavy Fuel Oil	0.8%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
d. Light Fuel Oil	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Natural Gas-Boiler	0.4%	0.2%	0.2%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%
f. Natural Gas-Combined Cycle	7.6%	10.9%	16.1%	13.7%	11.8%	20.2%	24.2%	26.0%	24.5%	32.0%	31.2%	33.0%	33.0%	32.5%	33.4%	32.8%	32.7%	38.2%	38.3%
g. Natural Gas-Turbine	1.9%	1.1%	1.4%	1.3%	0.9%	0.9%	0.8%	1.0%	0.9%	0.9%	0.9%	1.2%	1.5%	1.6%	1.7%	1.8%	1.7%	1.6%	1.6%
h. Hydro-Conventional	1.4%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
i. Hydro-Pumped Storage	3.3%	3.0%	3.0%	2.7%	2.4%	2.2%	2.4%	2.1%	2.7%	1.8%	2.0%	2.0%	2.1%	2.3%	2.2%	2.2%	2.3%	1.9%	1.9%
j. Renewable Resources	0.5%	0.5%	0.4%	1.0%	1.8%	2.0%	2.2%	2.3%	2.4%	2.4%	2.5%	2.4%	2.4%	2.4%	2.3%	2.3%	2.3%	2.3%	2.2%
k. Total Generation	75.6%	71.3%	77.7%	81.6%	77.6%	80.8%	84.8%	88.4%	87.8%	92.7%	93.5%	94.1%	94.5%	91.7%	91.1%	89.8%	89.5%	92.2%	91.6%
l. Purchased Power	29.2%	33.6%	27.5%	22.8%	26.2%	22.9%	19.7%	15.9%	16.5%	12.8%	12.1%	11.4%	10.9%	13.3%	13.5%	14.5%	14.8%	13.1%	13.5%
m. Direct Load Control (DLC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
n. Less Pumping Energy	-4.1%	-3.7%	-3.8%	-3.4%	-3.0%	-2.8%	-3.0%	-2.7%	-3.4%	-2.3%	-2.5%	-2.5%	-2.6%	-2.8%	-2.7%	-2.8%	-2.8%	-2.4%	-2.4%
o. Less Other Sales(1)	-0.7%	-1.1%	-1.5%	-1.0%	-0.8%	-0.8%	-1.4%	-1.6%	-0.9%	-3.2%	-3.1%	-2.9%	-2.8%	-2.1%	-1.8%	-1.6%	-1.5%	-3.0%	-2.7%
p. Total System Output	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	58.4%	58.4%	55.0%	57.4%	56.0%	55.9%	55.7%	57.9%	57.8%	57.6%	57.4%	57.4%	57.4%	57.4%	57.4%	57.4%	57.4%	57.4%	57.4%

(1) Economy energy.

APPENDIX 3I – PLANNED CHANGES TO EXISTING GENERATION UNITS

Company Name: Virginia Electric and Power Company

Schedule 13a

UNIT PERFORMANCE DATA(1)

Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)														
Unit Name	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Altavista	-	-	-	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County Units 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade CC	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bluestone	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick County CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 2, 4, 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clear Fork	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Covanta Fairfax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cushaw Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Doswell Complex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Power & Steam Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Edgecombe Genco (Rocky Mountain)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Extraction Partners	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic 3x1 CC 2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Double CT 2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Double CT 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Double CT 2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-	-	-	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell Cogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lost River	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).

APPENDIX 3I Cont. – PLANNED CHANGES TO EXISTING GENERATION UNITS

Company Name: Virginia Electric and Power Company

Schedule 13a

UNIT PERFORMANCE DATA(1)

Unit Size (MW) Uprate and Derate

Unit Name	(ACTUAL) 2010	2011	2012	2013	(PROJECTED) 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Mecklenburg 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	13	-	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SEI Birchwood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar NUG 2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 1 (Richmond 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, Facility 2 (Richmond 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren County CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).

APPENDIX 3I Cont. – PLANNED CHANGES TO EXISTING GENERATION UNITS

Company Name: Virginia Electric and Power Company

Schedule 13b

UNIT PERFORMANCE DATA(1)

Planned Changes to Existing Generation Units

Station / Unit Name	Uprate/Derate Description	Expected Removal Date	Expected Return Date	Base Rating	Revised Rating	MW
Bremo 3	Fuel Switch	N/A	2014	71	71	-
Bremo 4	Fuel Switch	N/A	2014	156	156	-
Hopewell	Fuel Switch	N/A	2013	63	51	-12
Mount Storm 1	Turbine Rotor	2013	2013	524	554	30
Southampton	Fuel Switch	N/A	2013	63	51	-12

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).

APPENDIX 3J – POTENTIAL UNIT RETIREMENTS

Company Name: Virginia Electric and Power Company — Schedule 19

UNIT PERFORMANCE DATA

Planned Unit Retirements[1]

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Possum Point CT	**Dumfries, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2015**	**72**	**106**
Possum Point GT1					12	
Possum Point GT2					12	
Possum Point GT3					12	
Possum Point GT4					12	
Possum Point GT5					12	
Possum Point GT6					12	
Yorktown 1	**Yorktown, VA**	**Steam-Cycle**	**Coal**	**2015**	**159**	**162**
Yorktown 2	**Yorktown, VA**	**Steam-Cycle**	**Coal**	**2015**	**164**	**165**
Chesapeake Energy Center	**Chesapeake, VA**	**Steam- Cycle**	**Coal**	**2015**	**595**	**605**
Chesapeake 1					111	
Chesapeake 2					111	
Chesapeake 3					156	
Chesapeake 4					217	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2016**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2016**	**11**	**15**
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2017**	**47**	**70**
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**15**	**20**
Chesapeake CT 2	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**36**	**49**
Chesapeake GT2					12	
Chesapeake GT4					12	
Chesapeake GT6					12	
Gravel Neck 1	**Surry, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**28**	**38**
Gravel Neck GT1					12	
Gravel Neck GT2					16	

(1) Reflects retirement assumptions used for planning purposes, not firm Company commitments.

APPENDIX 3K – PLANNED GENERATION UNDER CONSTRUCTION

Company Name: Virginia Electric and Power Company **Schedule 15a**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Nameplate
Under Construction						
Solar Partnership Program	Distributed	Intermittent	Solar	2015(2)	7	24
Warren County Power Station	Warren County, VA	Intermediate/ Baseload	Natural Gas	Dec-2014	1,337	1,337
Brunswick County Power Station	Brunswick County, VA	Intermediate/ Baseload	Natural Gas	May-2016	1,375	1,375

(1) Commercial Operation Date

(2) Phase 1 to be completed by 2013. Phase 2 to be completed by 2015.

APPENDIX 3L – WHOLESALE POWER SALES CONTRACTS

Company Name: Virginia Electric and Power Company

WHOLESALE POWER SALES CONTRACTS

Schedule 20

Entity	Contract Length	Contract Type	2010 (Actual)	2011 (Actual)	2012 (Actual)	2013 (Projected)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Old Dominion Electric Coop	12/31/2009	Non-Firm Partial Requirements[2]	600																		
North Carolina Electric Membership Coop	12/31/2014	Non-Firm Partial Requirements	150	150	150	150	150														
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	9	9	9	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12	13
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements[1][3]	236	321	358	338	339	341	345	350	355	359	365	369	374	378	381	385	389	393	397

(1) *Full requirements contracts do not have a specific contracted capacity amount. MWs are included in the Company's load forecast.*
(2) *ODEC contract expired year end 2010.*
(3) *VMEA contract reflects values as of Aug 2013.*

APPENDIX 3M – DESCRIPTION OF APPROVED AND EXTENDED DSM PROGRAMS

<u>Air Conditioner Cycling Program</u>

Branded Name:	Smart Cooling Rewards
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Peak-Shaving
NC Program Type:	Peak-Shaving
VA Duration:	Ongoing
NC Duration:	Ongoing

Program Description:

This Program provides participants with an external radio frequency cycling switch that operates on central air conditioners and heat pump systems. Participants allow the Company to cycle their central air conditioning and heat pump systems during peak load periods. The cycling switch is installed by a contractor and located on or near the outdoor air conditioning unit(s). The Company remotely signals the unit when peak load periods are expected, and the air conditioning or heat pump system is cycled off and on for short intervals.

Program Marketing:

Direct mail is currently the most frequently used marketing approach for this type of Program. The Company uses various enrollment methods including business reply cards, online enrollment, and call centers.

<u>Residential Low Income Program</u>

Branded Name:	Income Qualifying Home Improvement Program
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Ongoing
NC Duration:	Ongoing

Program Description:

The Low Income Program provides an energy audit for residential customers who meet the low income criteria defined by state social service agencies. A certified technician performs an audit of participating residences to determine potential energy efficiency improvements. Specific energy efficiency measures applied may include, but are not limited to: envelope sealing, water heater temperature set point reduction, installation of insulation wrap around the water heater and pipes, installation of low flow shower head(s), replacement of incandescent lighting with efficient lighting, duct sealing, attic insulation, and air filter replacement.

Program Marketing:
The Company markets this Program using a neighborhood canvassing approach in prescreened areas targeting income qualifying customers. To ensure neighborhood security and program legitimacy, community posters, truck decals, yard signs, and authorization forms have been produced and are displayed in areas where the Program has current activity.

Non-Residential Distributed Generation Program

Branded Name:	Distributed Generation
State:	Virginia
Target Class:	Commercial and Industrial
VA Program Type:	Demand-Side Management
VA Duration:	2012 – 2038

Program Description:
As part of this Program, a third party contractor will dispatch, monitor, maintain and operate customer-owned generation when called upon by the Company during peak demand periods for up to 120 hours per year, throughout all months. The Company will supervise and implement the CDG Program through the third party implementation contractor. Participating customers will essentially receive reduced-cost backup generation service in exchange for their agreement to reduce electrical load on the Company's system. The reduction in cost of the backup generation service is facilitated through a fee paid by the Company to the third party contractor, based upon the amount of load curtailment delivered during control events. At least 80% of the program participation incentive is required to be passed through to the customer, with 100% of fuel and operations and maintenance compensation passed along to the customer. When not being dispatched by the Company, the generators may be used at the participants' discretion or to supply power during an outage, consistent with applicable environmental restrictions.

Program Marketing:
Marketing will be handled by the Company's implementation vendor.

Non-Residential Energy Audit Program

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2038
NC Duration:	2014 – 2038

Program Description:
As part of this Program, an energy auditor will perform an on-site energy audit of a non-residential customer's facility. The customer will receive a report showing the projected energy and cost savings that could be anticipated from the implementation of options identified during the audit. Once a qualifying customer provides documentation that some of the recommended energy efficiency improvements have been made at the customer's expense, a portion of the audit value will be refunded.

Program Marketing:
The Company has a number of marketing activities planned for its recently approved DSM Programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Non-Residential Duct Testing & Sealing Program

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2038
NC Duration:	2014 – 2038

Program Description:
This Program will promote testing and general repair of poorly performing duct and air distribution systems in non-residential facilities. The Program provides incentives to qualifying customers to have a contractor seal ducts in existing buildings using program-approved methods, including: aerosol sealant, mastic, or foil tape with an acrylic adhesive. Such systems include air handlers, air intake, return and supply plenums, and any connecting duct work.

Program Marketing:
The Company has a number of marketing activities planned for its recently approved DSM Programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Residential Bundle Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2038
NC Duration:	2014 – 2038

The Residential Bundle Program includes the four DSM Programs described below.

Program Marketing:
The Company has a number of marketing activities planned for its recently approved DSM Programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Residential Home Energy Check-Up Program
Program Description:
The purpose of this Program is to provide owners and occupants of single family homes an easy and low cost home energy audit. It will include a walk-through audit of customer homes, direct install measures, and recommendations for additional home energy improvements.

Residential Duct Testing & Sealing Program
Program Description:
This Program is designed to promote the testing and repair of poorly performing duct and air distribution systems. Qualifying customers will be provided an incentive to have a contractor test and seal ducts in their homes using methods approved for the Program, such as mastic material or foil tape with an acrylic adhesive to seal all joints and connections. The repairs are expected to reduce the average air leakage of a home's conditioned floor area to industry standards.

Residential Heat Pump Tune-Up Program
Program Description:
This Program provides qualifying customers with an incentive to have a contractor tune-up their existing heat pumps once every five years in order to achieve maximum operational performance. A properly tuned system should increase efficiency, reduce operating costs, and prevent premature equipment failures.

Residential Heat Pump Upgrade Program
Program Description:
This Program provides incentives for residential heat pump (e.g., air and geothermal) upgrades. Qualifying equipment must have better Seasonal Energy Efficiency Ratio and Heating Seasonal Performance Factor ratings than the current nationally mandated efficiency standards.

APPENDIX 3N – APPROVED AND EXTENDED PROGRAMS NON-COINCIDENTAL PEAK SAVINGS

(kW) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Air Conditioner Cycling Program	78,321	94,758	114,482	134,206	153,930	173,654	182,739	184,766	186,364	186,896	185,184	186,451	187,701	188,953	190,210	191,460
Residential Low Income Program	3,081	3,548	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,870	3,335	2,045	1,240	593
Residential Lighting Program	108,277	108,277	108,277	108,277	108,277	108,277	106,070	79,902	56,811	28,550	0	0	0	0	0	0
Commercial Lighting Program	14,855	14,855	14,855	14,855	14,855	14,855	13,443	9,997	3,462	0	0	0	0	0	0	0
Commercial HVAC Program	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,180	890	347	0
Non-Residential Energy Audit Program	1,494	5,923	11,645	17,938	20,232	20,541	20,773	20,985	21,191	21,396	21,600	21,805	22,009	22,235	22,475	22,718
Non-Residential Duct & Sealing Program	1,719	5,176	9,810	14,886	17,229	17,494	17,685	17,847	18,004	18,157	18,308	18,456	18,602	18,749	18,895	19,041
Non-Residential Distributed Generation Program	29,536	36,920	36,920	44,304	51,688	56,962	58,017	59,072	60,127	61,181	62,236	63,291	64,346	65,401	66,456	67,510
Residential Bundle Program	12,053	31,300	54,104	80,354	92,247	98,983	104,308	105,201	106,068	106,917	107,755	108,597	109,436	110,294	111,301	112,312
Residential Home Energy Check-Up Program	263	677	1,164	1,715	1,931	1,987	2,023	2,044	2,065	2,088	2,106	2,127	2,147	2,170	2,196	2,222
Residential Duct & Sealing Program	687	2,138	3,997	6,024	6,997	7,147	7,237	7,314	7,388	7,461	7,535	7,608	7,682	7,765	7,857	7,949
Residential Heat Pump Tune Up Program	6,610	16,771	28,731	43,455	51,019	56,609	61,335	61,988	62,626	63,250	63,869	64,494	65,119	65,751	66,521	67,300
Residential Heat Pump Upgrade Program	4,494	11,714	20,211	29,160	32,299	33,240	33,713	33,855	33,989	34,118	34,244	34,368	34,488	34,608	34,728	34,847
Total	250,679	302,099	355,343	420,070	463,708	496,017	508,286	483,022	457,278	428,348	400,334	403,812	406,609	408,567	410,923	413,635

Note: Residential Bundle Program includes Residential Home Energy Check-up, Residential Duct Testing & Sealing, Residential Heat Pump Tune-Up, and Residential Heat Pump Upgrade Programs; Maximum impact occurs at different times of the day; Assume year end penetrations.

APPENDIX 3O – APPROVED AND EXTENDED PROGRAMS COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Air Conditioner Cycling Program	75,034	94,758	114,482	134,206	153,930	173,654	182,739	183,880	184,393	184,458	185,184	186,451	187,701	188,953	190,210	191,460
Residential Low Income Program	1,179	1,434	1,540	1,540	1,540	1,540	1,540	1,540	1,540	1,540	1,540	1,434	1,052	644	361	106
Residential Lighting Program	21,698	21,698	21,698	21,698	21,698	21,698	18,602	13,743	8,579	2,601	0	0	0	0	0	0
Commercial Lighting Program	14,855	14,855	14,855	14,855	14,855	14,855	13,435	7,766	1,850	0	0	0	0	0	0	0
Commercial HVAC Program	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,170	683	176	0
Non-Residential Energy Audit Program	1,045	3,790	8,562	13,411	15,644	15,887	16,068	16,232	16,391	16,549	16,706	16,864	17,022	17,194	17,380	17,567
Non-Residential Duct & Sealing Program	1,340	4,270	8,092	12,279	14,212	14,431	14,589	14,722	14,851	14,978	15,102	15,224	15,345	15,466	15,587	15,707
Non-Residential Distributed Generation Program	25,598	33,843	36,920	41,227	48,611	54,764	57,577	58,632	59,687	60,742	61,797	62,852	63,906	64,961	66,016	67,071
Residential Bundle Program	6,197	19,995	38,102	58,019	67,820	72,919	76,279	76,944	77,591	78,228	78,864	79,500	80,133	80,842	81,609	82,384
Residential Home Energy Check-Up Program	143	467	890	1,357	1,583	1,629	1,659	1,676	1,693	1,710	1,727	1,744	1,760	1,779	1,800	1,821
Residential Duct & Sealing Program	554	1,842	3,532	5,391	6,292	6,427	6,508	6,576	6,643	6,709	6,775	6,842	6,908	6,983	7,065	7,148
Residential Heat Pump Tune Up Program	3,691	11,709	22,230	33,803	39,560	44,041	47,109	47,603	48,084	48,559	49,034	49,512	49,987	50,527	51,118	51,717
Residential Heat Pump Upgrade Program	1,808	5,978	11,450	17,468	20,385	20,821	21,003	21,089	21,171	21,250	21,328	21,404	21,478	21,553	21,625	21,698
Total	148,289	195,986	245,594	298,579	339,653	371,091	382,172	374,803	366,226	360,438	360,536	363,668	366,329	368,743	371,338	374,296

Note: Residential Bundle Program includes Residential Home Energy Check-up, Residential Duct Testing & Sealing, Residential Heat Pump Tune-Up, and Residential Heat Pump Upgrade Programs; Assume year end penetrations.

APPENDIX 3P – APPROVED AND EXTENDED PROGRAMS ENERGY SAVINGS
(MWh) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Low Income Program	7,505	9,151	9,947	9,947	9,947	9,947	9,947	9,947	9,947	9,947	9,947	9,339	7,019	4,301	2,442	796
Residential Lighting Program	276,473	276,473	276,473	276,473	276,473	276,473	239,838	177,519	112,293	36,450	0	0	0	0	0	0
Commercial Lighting Program	121,053	121,053	121,053	121,359	121,053	121,053	110,196	65,855	16,383	0	0	0	0	0	0	0
Commercial HVAC Program	7,299	7,299	7,299	7,307	7,299	7,299	7,299	7,307	7,299	7,299	7,299	7,307	6,443	3,887	1,077	0
Non-Residential Energy Audit Program	5,550	21,796	50,425	79,988	94,700	96,203	97,320	98,325	99,297	100,259	101,221	102,186	103,148	104,198	105,328	106,471
Non-Residential Duct & Sealing Program	5,726	18,726	35,842	54,762	63,915	64,910	65,627	66,377	66,811	67,380	67,940	68,643	69,033	69,576	70,121	70,821
Non-Residential Distributed Generation Program	187	186	15	14	22	602	1,251	45	63	64	186	1,533	29	43	48	878
Residential Bundle Program	17,354	59,748	116,661	179,784	215,333	231,161	244,189	246,349	248,452	250,520	252,582	254,648	256,702	258,973	261,467	263,988
Residential Home Energy Check-Up Program	781	2,620	5,056	7,752	9,152	9,420	9,597	9,698	9,796	9,893	9,990	10,088	10,185	10,295	10,415	10,538
Residential Duct & Sealing Program	827	2,865	5,576	8,572	10,149	10,373	10,506	10,617	10,725	10,831	10,938	11,045	11,151	11,271	11,404	11,538
Residential Heat Pump Tune Up Program	11,078	37,543	73,090	112,520	134,947	148,898	161,013	162,703	164,353	165,978	167,603	169,236	170,863	172,680	174,702	176,748
Residential Heat Pump Upgrade Program	4,669	16,720	32,939	50,941	61,085	62,470	63,073	63,332	63,578	63,817	64,051	64,279	64,503	64,728	64,946	65,164
Total	441,148	514,433	617,715	729,635	788,743	807,648	775,668	671,726	560,545	471,918	439,175	443,656	442,375	440,979	440,483	442,953

Note: Residential Bundle Program includes Residential Home Energy Check-up, Residential Duct Testing & Sealing, Residential Heat Pump Tune-Up, and Residential Heat Pump Upgrade Programs; Year end projections.

APPENDIX 3Q – APPROVED AND EXTENDED PROGRAMS PENETRATIONS
(System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Air Conditioner Cycling Program	81,389	101,389	121,389	141,389	161,389	181,389	182,895	184,310	185,679	187,014	188,318	189,590	190,854	192,127	193,402	194,665
Residential Low Income Program	10,087	12,087	12,087	12,087	12,087	12,087	12,087	12,087	12,087	12,087	12,087	10,656	6,536	4,000	2,000	0
Residential Lighting Program[1]	7,798,234	7,798,234	7,798,234	7,798,234	7,798,234	7,798,234	5,890,547	4,259,629	2,243,150	0	0	0	0	0	0	0
Commercial Lighting Program[2]	2,435	2,435	2,435	2,435	2,435	2,435	2,036	728	0	0	0	0	0	0	0	0
Commercial HVAC Program[2]	127	127	127	127	127	127	127	127	127	127	127	127	99	40	0	0
Non-Residential Energy Audit Program[2]	391	1,643	3,103	4,641	4,731	4,796	4,848	4,897	4,946	4,995	5,044	5,093	5,142	5,199	5,257	5,315
Non-Residential Duct & Sealing Program[2]	324	826	1,414	2,031	2,069	2,096	2,116	2,135	2,153	2,171	2,189	2,207	2,224	2,242	2,259	2,276
Non-Residential Distributed Generation Program	28	35	35	42	49	54	55	56	57	58	59	60	61	62	63	64
Residential Bundle Program	46,217	118,890	204,423	294,512	304,637	338,014	341,098	344,096	347,019	349,916	352,826	355,734	358,614	362,122	365,652	369,234
Residential Home Energy Check-Up Program	1,636	4,223	7,266	10,487	10,801	11,112	11,231	11,347	11,461	11,573	11,687	11,801	11,913	12,053	12,194	12,338
Residential Duct & Sealing Program	3,464	9,059	15,646	22,581	23,266	23,621	23,875	24,123	24,365	24,605	24,846	25,089	25,329	25,627	25,928	26,233
Residential Heat Pump Tune Up Program	29,039	74,109	127,154	183,015	189,755	221,241	223,604	225,912	228,164	230,401	232,654	234,913	237,149	239,926	242,735	245,578
Residential Heat Pump Upgrade Program	12,078	31,499	54,357	78,429	80,815	82,040	82,387	82,714	83,030	83,338	83,638	83,932	84,223	84,517	84,794	85,085
Total	7,939,232	8,035,666	8,143,247	8,255,498	8,285,758	8,339,232	6,435,808	4,808,065	2,795,219	556,369	560,650	563,467	563,530	565,792	568,633	571,555

Note: Residential Bundle Program includes Residential Home Energy Check-up, Residential Duct Testing & Sealing; Residential Heat Pump Tune-Up, and Residential Heat Pump Upgrade Programs; Assume year end penetrations.

(1) Number of bulbs.

(2) Program penetrations have been adjusted for exempt customers.

APPENDIX 3R – PROPOSED PROGRAM NON-COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Non-Residential Solar Window Film Program	0	396	2,760	7,231	12,929	19,137	21,243	21,588	21,807	22,022	22,233	22,441	22,647	22,854	23,062	23,268
Non-Residential Lighting Systems & Controls Program	0	6,179	18,713	31,457	44,394	59,270	61,065	61,710	62,336	62,950	63,554	64,148	64,738	65,328	65,920	66,509
Non-Residential Heating & Cooling Efficiency Program	0	1,297	5,770	11,666	18,339	25,115	28,702	29,069	29,443	29,805	30,147	30,470	30,783	31,089	31,390	31,687
Total	0	7,872	27,243	50,354	75,662	103,522	111,010	112,366	113,585	114,777	115,934	117,060	118,168	119,271	120,371	121,464

APPENDIX 3S – PROPOSED PROGRAM COINCIDENTAL PEAK SAVINGS
(kW) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Non-Residential Solar Window Film Program	0	124	1,818	5,133	9,572	14,502	16,937	17,279	17,455	17,628	17,798	17,965	18,130	18,296	18,462	18,628
Non-Residential Lighting Systems & Controls Program	0	1,773	13,550	26,262	39,175	53,305	59,911	60,547	61,163	61,767	62,361	62,945	63,524	64,104	64,685	65,264
Non-Residential Heating & Cooling Efficiency Program	0	171	1,662	3,537	5,472	7,436	8,319	8,425	8,533	8,638	8,736	8,830	8,920	9,008	9,095	9,181
Total	0	2,068	17,029	34,932	54,219	75,243	85,167	86,251	87,153	88,032	88,895	89,740	90,574	91,408	92,242	93,073

APPENDIX 3T – PROPOSED PROGRAM ENERGY SAVINGS
(MWh) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017	2028
Non-Residential Solar Window Film Program	0	672	8,101	23,224	43,656	66,415	78,253	79,882	80,697	81,496	82,282	83,056	83,822	84,588	85,357	86,123
Non-Residential Lighting Systems & Controls Program	0	7,358	46,479	91,838	137,916	188,074	213,821	216,095	218,296	220,454	222,576	224,665	226,732	228,800	230,875	232,944
Non-Residential Heating & Cooling Efficiency Program	0	883	6,759	14,388	22,259	30,248	33,838	34,272	34,712	35,137	35,538	35,917	36,284	36,644	36,998	37,347
Total	0	8,913	61,339	129,450	203,831	284,737	325,912	330,249	333,705	337,087	340,296	343,638	346,838	350,032	353,230	356,414

APPENDIX 3U – PROPOSED PROGRAM PENETRATIONS
(System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Non-Residential Solar Window Film Program	0	133,086	862,040	2,086,859	3,549,755	5,100,436	5,275,372	5,330,182	5,383,788	5,436,463	5,488,318	5,539,331	5,590,082	5,641,083	5,692,173	5,742,941
Non-Residential Lighting Systems & Controls Program	0	1,644	4,978	8,368	11,809	15,766	15,938	16,104	16,265	16,424	16,580	16,734	16,887	17,041	17,195	17,348
Non-Residential Heating & Cooling Efficiency Program	0	261	1,055	1,889	2,739	3,599	3,644	3,692	3,738	3,783	3,825	3,865	3,904	3,942	3,980	4,017
Total	0	134,991	868,073	2,097,116	3,564,303	5,119,801	5,294,954	5,349,977	5,403,792	5,456,670	5,508,722	5,559,930	5,610,873	5,662,066	5,713,347	5,764,305

APPENDIX 3V – DESCRIPTION OF PROPOSED DSM PROGRAMS

Non-Residential Solar Window Film Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2038
NC Duration:	2015 – 2038

Program Description:
This Program provides qualifying non-residential customers with an incentive to install solar reduction window film to lower their cooling bills and improve occupant comfort.

Non-Residential Heating and Cooling Efficiency Program

Branded Name:	HVAC Rewards
State:	Virginia & North Carolina
Target Class:	Commercial and Industrial
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2038
NC Duration:	2015 – 2038

Program Description:
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing HVAC equipment to more efficient HVAC technologies that can produce verifiable savings.

Non-Residential Lighting Systems and Controls Program

Branded Name:	Lighting Rewards
State:	Virginia & North Carolina
Target Class:	Commercial and Industrial
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2038
NC Duration:	2015 – 2038

Program Description:
This Program provides qualifying non-residential customers with an incentive to implement more efficient lighting technologies that can produce verifiable savings. The Program promotes the installation of lighting technologies including but not limited to compact fluorescent bulbs, light emitting diode based bulbs, and lighting control systems.

APPENDIX 3W– GENERATION INTERCONNECTION PROJECTS UNDER CONSTRUCTION

Line Terminal	PJM Queue	Line Voltage (kV)	Line Capacity (MVA)	Interconnection Cost (Million $)	Target Date	Location
Warren	V2-030	500	3,424	7.8	Dec-14	VA
Carson - Wake	X2-076	500	3,424	89.1	May-15	VA

APPENDIX 3X – LIST OF TRANSMISSION LINES UNDER CONSTRUCTION

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #65 Uprate (Garner - Lancaster)	115	217	Sep-13	VA
Lexington - Cloverdale Line # 566 Uprate	500	4,000	Dec-13	VA
Line 270 - Burke to Sideburn - Install 2nd UG 230kV Cable	230	586	Mar-14	VA
N 301 Industrial Park 115kV DP (HEMC)	115	261	Apr-14	NC
Hollymead Tap Rebuild	230	1,047	May-14	VA
Dooms to Bremo 230kV Transmission Line Rebuild	115	240	May-14	VA
Dahlgren Substation 230kV Line (Loop Line #2076)	230	1,047	May-14	VA
Line #69 Uprate	115	263	May-14	VA
Line #148 Uprate	115	162	May-14	VA
Glebe-Radnor Heights-Ballston 230kV UG Line	230	354	Jun-14	VA
Line #100 Rebuild between Chesterfield - Harrowgate	115	398	Jun-14	VA
Northwest to Lakeside 230kv Line	230	1,047	Jun-14	VA
Cannon Branch to Cloverhill - New 230kV Line	230	1,047	Jul-14	VA
Convert Line 64 to 230kV and Install 230kV Capacitor Bank at Winfall	230	775 (#2131) 840(#2126)	Dec-14	NC
Rebuild Line #551 (Mt Storm - Doubs)	500	4,334	Dec-14	VA
Line #296 Reconductor Halifax to Dominion/Progress Dividing Line	230	712	Feb-15	VA/NC
Shawboro – Aydlett Tap 230kV Line	230	751	May-15	NC
Cloverhill to Liberty - New 230kV Line	230	1,047	May-15	VA
2nd 230kV Line Harrisonburg to Endless Caverns	230	1,047	Jun-15	VA
Line #30 Rebuild (Altivista to Skimmer)	115	239	Jun-15	VA
Rebuild Dooms to Lexington 500 kV Line	500	4,000	Dec-15	VA

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4A BASECASE PRICE FORECAST (2012 REAL $)

	Fuel Price					Power and REC Prices				Emission Prices			
Year	Henry Hub Natural Gas ($/MMbtu)	DOM Zone Delivered Natural Gas ($/MMbtu)	CAPP CSX: 12,500 1%S FOB ($/MMbtu)	No. 2 Oil ($/MMbtu)	1% No. 6 Oil ($/MMbtu)	PJM-DOM On-Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	RTO Capacity Prices ($/KW-yr)	CAIR SO2 ($/Ton)	CAIR Ozone Nox ($/Ton)	CAIR Annual Nox ($/Ton)	CO2 Tax ($/Ton)
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*****EXTRAORDINARILY SENSITIVE INFORMATION REDACTED *****
APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST; NATURAL GAS

DOM Zone Natural Gas Price (2012 Real $/MMbtu)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]

(1) DOM Zone natural gas price used in plan analysis.

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4B Cont. BASECASE AND SCENARIO PRICE FORECAST; NATURAL GAS

Henry Hub Natural Gas Price (2012 Real $/MMbtu)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				

(1)DOM Zone natural gas price used in plan analysis. Henry Hub prices shown to provide market reference.

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST; COAL: FOB

CAPP 12,500 1%S Coal (2012 Real $/MMbtu)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST; OIL

No. 2 Oil (2012 Real$/MMbtu)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST;
OIL

1% No. 6 Oil (2012 Real $/MMbtu)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015	[redacted]			
2016	[redacted]			
2017	[redacted]			
2018	[redacted]			
2019	[redacted]			
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST;
ON-PEAK POWER PRICE

DOM Zone Power On-Peak (2012 Real $/MWh)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST; OFF-PEAK POWER PRICE

DOM Zone Power Off-Peak (2012 Real $/MWh)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015	[redacted]			
2016	[redacted]			
2017	[redacted]			
2018	[redacted]			
2019	[redacted]			
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			

*****EXTRAORDINARILY SENSITIVE INFORMATION REDACTED *****

**APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST;
PJM TIER 1 RENEWABLE ENERGY CERTIFICATES**

PJM Tier 1 REC Prices (2012 Real $/MWh)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST;
PJM RTO CAPACITY

RTO Capacity Prices (2012 Real $/KW-yr)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST;
SO_2 EMISSION ALLOWANCES

CAIR SO2 Prices (2012 Real$/Ton)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015	[redacted]			
2016	[redacted]			
2017	[redacted]			
2018	[redacted]			
2019	[redacted]			
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***
APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST;
NOx EMISSION ALLOWANCES

CAIR Annual Nox Prices (2012 Real $/Ton)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015	[redacted]			
2016	[redacted]			
2017	[redacted]			
2018	[redacted]			
2019	[redacted]			
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			

***EXTRAORDINARILY SENSITIVE INFORMATION REDACTED ***

APPENDIX 4B BASECASE AND SCENARIO PRICE FORECAST; CO_2

CO2 (2012 Real $/Ton)				
Year	Basecase	High Fuel Cost	Low Fuel Cost	No CO2 Cost
2014	[redacted]			
2015	[redacted]			
2016	[redacted]			
2017	[redacted]			
2018	[redacted]			
2019	[redacted]			
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 4C – DELIVERED FUEL DATA

Company Name: Virginia Electric and Power Company — Schedule 18

FUEL DATA

	(ACTUAL)			(PROJECTED)															
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. Delivered Fuel Price ($/mmBtu)[1]																			
a. Nuclear	0.60	0.63	0.68	[redacted]															
b. Coal	3.05	3.21	3.15																
c. Heavy Fuel Oil	11.49	16.04	15.27																
d. Light Fuel Oil[2]	15.48	19.70	19.89																
e. Natural Gas	6.44	4.51	3.07																
f. Renewable[3]	2.13	2.13	1.85																
II. Primary Fuel Expenses (cents/kWh)[4]																			
a. Nuclear	0.60	0.66	0.71	[redacted]															
b. Coal	3.22	3.36	3.22																
c. Heavy Fuel Oil	8.93	10.69	13.91																
d. Light Fuel Oil[2]	16.24	12.92	4.57																
e. Natural Gas	4.72	3.88	2.76																
f. Renewable[3]	3.43	3.37	2.95																
g. NUG[5]	3.74	3.64	3.02																
i. Economy Energy Purchases[6]	5.06	4.62	3.78																
j. Capacity Purchases ($/kW-Year)	52.63	49.93	20.24																

(1) Delivered fuel price for CAPP CSX (12,500, 1% FOB), No. 2 Oil, No. 6 Oil, DOM Zone Delivered Natural Gas are used to represent Coal, Heavy Fuel, Light Fuel Oil and Natural Gas respectively.
(2) Light fuel oil is used for reliability only at dual-fuel facilities.
(3) Per definition of Va. Code § 56-576.
(4) Primary Fuel Expenses for Nuclear, Coal, Heavy Fuel Oil, Light Fuel Oil, Natural Gas and Renewable are based on North Anna 1, Chesterfield 6, Yorktown 3, Possum Point 6, Pittsylvania, respectively.
(5) Average of NUGs Fuel Expenses.
(6) Average cost of Market Energy Purchases.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 5A – TABULAR RESULTS OF BUSBAR

	Capacity Factor (%)										
$/kW-Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
CT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CC 3x1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CC 2x1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar Tag	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar PV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Onshore Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Offshore Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Biomass	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IGCC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IGCC CCS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCPC CCS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED
EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 5B – BUSBAR ASSUMPTIONS

Nominal $	Heat Rate	Variable Cost	Fixed Cost	Book Life	2013 Real $
	MMBtu/MWh	$/MWh	$/kW-Year	Years	$/kW
CT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CC 3x1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CC 2x1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar Tag	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar PV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Onshore Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Offshore Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Biomass	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IGCC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IGCC CCS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCPC CCS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

APPENDIX 5C – PLANNED GENERATION UNDER DEVELOPMENT

Company Name: Virginia Electric and Power Company — Schedule 15c

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Nameplate
Under Development						
Offshore Wind Demonstration Project	VA	Intermittent	Wind	2018	2	12
Generic CC 3x1 2019	N/A	Intermediate/ Baseload	Natural Gas-CC	N/A	1,375	1,375
North Anna 3	Mineral, VA	Baseload	Nuclear	2024	1,453	1,453
Solar Tag 2017	N/A	Intermittent	Solar	N/A	4	10
Solar Tag 2020	N/A	Intermittent	Solar	N/A	4	10
Solar 2017	N/A	Intermittent	Solar	N/A	16	40
Solar 2018	N/A	Intermittent	Solar	N/A	16	40
Solar 2019	N/A	Intermittent	Solar	N/A	16	40
Solar 2020	N/A	Intermittent	Solar	N/A	16	40
Solar 2021	N/A	Intermittent	Solar	N/A	16	40
Wind 1: 2022	N/A	Intermittent	Wind	N/A	16	120
Wind 2: 2023	N/A	Intermittent	Wind	N/A	10	80
Wind 3: 2024	N/A	Intermittent	Wind	N/A	6	48

(1) Commercial Operation Date.

APPENDIX 5D – STANDARD DSM TEST DESCRIPTIONS

Participant Test

The Participant test is the measure of the quantifiable benefits and costs to program participants due to enrollment in a program. This test indicates whether the program or measure is economically attractive to the customer enrolled in the program. Benefits include the participant's retail bill savings over time plus any incentives offered by the utility, while costs include only the participant's costs. A result of 1.0 or higher indicates that a program is beneficial for the participant.

Utility Cost Test

The Utility Cost test compares the cost to the utility to implement a program to the cost that is expected to be avoided as a result of the program implementation. The Utility Cost test measures the net costs and benefits of a DSM program as a resource option, based on the costs and benefits incurred by the utility including incentive costs and excluding any net costs incurred by the participant. The Utility Cost test ignores participant costs, meaning that a measure could pass the Utility Cost test, but may not be cost-effective from a more comprehensive perspective. A result of 1.0 or higher indicates that a program is beneficial for the utility.

Total Resource Cost Test

The TRC test compares the total costs and benefits to the utility and participants, relative to the costs to the utility and participants. It can also be viewed as a combination of the Participant and Utility Cost tests, measuring the impacts to the utility and all program participants as if they were treated as one group. Additionally, this test considers customer incentives as a pass-through benefit to customers and, therefore, does not include customer incentives. If a program passes the TRC test, then it is a viable program absent any equity issues associated with non-participants. A result of 1.0 or higher indicates that a program is beneficial for both participants and the utility.

Ratepayer Impact Measure Test

The RIM test considers equity issues related to programs. This test determines the impact the DSM program will have on non-participants and measures what happens to customer bills or rates due to changes in utility revenues and operating costs attributed to the program. A score on the RIM test of greater than 1.0 indicates the program is beneficial for both participants and non-participants, because it should have the effect of lowering bills or rates even for customers not participating in the program. Conversely, a score on the RIM test of less than 1.0 indicates the program is not as beneficial because the costs to implement the program exceed the benefits shared by all customers, including non-participants.

APPENDIX 5E – DSM PROGRAMS ENERGY SAVINGS (MWh)
(System-Level)

Company Name: Virginia Electric & Power Company

Schedule 12

Energy Efficiency/Energy Efficiency- Demand Response/Peak Shaving/Demand Side Management (MWh)

Program Type (1)	Program Name	Date (2)	Life/ Duration (3)	Size (MW) (4)	ACTUAL - MWH 2010	2011	2012	2013	(PROJECTED - MWH) 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Shaving	Air Conditioner Cycling Program (5)(10)	2010	2030	191,460	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal				191,460	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency - Demand Response	Non-Residential Distributed Generation Program (7)	2010 (6)	2030	87,871	1,085	839		187	188	15	14	22	677	1,251	46	43	84	188	1,533	29	43	48	878
	Standby Generation & Curtailable Service (Pricing Tariffs) (6)	1987	2030	8	875	308	356	840	840	840	800	800	800	800	800	800	800	800	800	800	800	800	800
Subtotal				87,879	2,360	917	356	1,027	1,028	855	814	822	1,263	1,851	846	843	844	988	2,333	829	843	848	1,479
Energy Efficiency	Residential Low Income Program (6)	2010	2029	108	787	2,831	4,083	7,885	8,151	8,847	8,847	8,847	8,847	8,847	8,847	8,847	8,847	8,847	8,339	7,018	4,201	2,442	788
	Residential Lighting Program (11)	2010	2028	0	184,120	228,082	228,082	278,473	278,473	278,473	278,473	278,473	278,473	230,850	177,819	112,293	38,450	-	-	-	-	-	-
	Commercial Lighting Program (8)	2010	2026	0	13,056	51,149	73,820	121,053	121,053	121,053	121,309	121,053	121,053	110,190	68,858	18,333		-	-	-	-	-	-
	Commercial HVAC Program (11)	2010	2026	8	481	5,803	3,890	7,280	7,299	7,289	7,297	7,289	7,289	7,289	7,307	7,289	7,289	7,289	7,307	8,443	3,887	1,077	-
	Non-Residential Energy Audit Program	2010	2029	17,887	-	-	28	5,880	21,790	50,429	79,886	84,700	88,203	87,320	88,325	98,297	100,259	101,221	102,186	103,148	104,198	105,379	106,471
	Non-Residential Duct & Sealing Program	2012	2026	15,707	-	-	70	3,730	18,726	38,842	54,782	63,915	64,819	66,027	66,377	66,611	67,380	67,840	68,043	69,023	69,571	70,121	70,821
	Residential Bundle Program (9)	2010 (9)	2029	92,894	-	-	238	17,364	68,749	118,881	179,784	215,333	231,181	244,188	248,349	249,452	250,928	252,582	254,846	256,702	258,073	261,467	263,888
	Residential Home Energy Check-Up Program (9)	2012	2030	1,821	-	-	28	731	2,820	5,088	7,792	8,152	8,430	8,587	8,695	8,796	8,893	8,980	10,089	10,188	10,295	10,415	10,536
	Residential Duct & Sealing Program (9)	2012	2030	7,149	-	-	8	877	2,485	5,576	8,573	10,148	10,273	10,508	10,617	10,725	10,831	10,930	11,045	11,151	11,271	11,404	11,530
	Residential Heat Pump Tune Up Program (9)	2012	2026	51,717	-	-	336	11,078	37,843	73,080	112,820	134,847	148,886	161,013	162,783	164,383	166,078	167,803	168,228	170,883	172,880	174,782	176,748
	Residential Heat Pump Upgrade Program (9)	2012	2026	21,808	-	-	170	4,807	18,730	32,830	50,841	61,805	62,470	63,073	63,373	63,570	64,017	64,051	64,379	64,803	64,720	64,848	65,184
	Non-Residential Solar Window Film Program	2014	2026	18,870	-	-	-	-	372	8,101	23,724	43,650	68,418	76,253	79,662	80,807	81,408	82,282	83,058	83,877	84,588	85,357	86,123
	Non-Residential Lighting Systems & Controls Program	2014	2028	65,204	-	-	-	-	7,358	45,479	91,838	137,818	188,074	213,821	216,088	218,298	220,454	222,578	224,643	226,732	228,830	230,875	232,944
	Non-Residential Heating & Cooling Efficiency Program	2014	2024	8,101	-	-	-	-	893	6,759	14,288	23,259	30,249	33,038	34,272	34,713	35,137	35,538	35,917	36,264	36,644	36,994	37,347
	Voltage Conservation Program (6)	2014	2029		5,487	5,833	25,773	27,846	34,124	108,048	310,048	723,264	1,081,548	1,493,621	1,730,243	1,842,814	1,883,421	2,037,358	2,037,358	2,037,358	2,037,358	2,037,358	2,037,358
	Non-Residential Re-Commissioning Program	2014	2026	22	-	-	-	-	-	170	1,834	3,363	5,463	9,854	12,313	12,779	12,844	12,814	11,884	9,962	7,887	3,941	1,407
	Non-Residential Custom Incentive Program	2014	2030	74,279	-	-	-	-	-	7,813	61,379	108,464	172,086	238,092	254,489	273,177	275,858	278,883	281,387	284,007	286,618	289,223	291,855
	New Residential Low Income Program (13)	2013	2029	2,988	-	-	-	-	-	578	3,620	7,410	11,334	15,378	17,083	18,088	18,378	18,580	18,771	18,877	18,177	18,372	18,985
Subtotal				705,110	182,992	293,796	337,890	468,868	587,293	796,447	1,334,417	1,835,887	2,272,634	2,645,879	2,833,408	3,041,159	3,079,886	3,125,862	3,128,941	3,139,867	3,141,799	3,142,370	3,148,675
Total Demand Side Management				944,034	185,292	294,711	338,254	469,932	584,299	797,302	1,335,079	1,836,479	2,273,936	2,646,292	2,834,263	3,041,972	3,080,281	3,127,860	3,137,274	3,140,130	3,142,272	3,144,218	3,150,153

(1) The Program types have been categorized by the Virginia definitions of peak-shaving, energy efficiency, and demand response.
(2) Implementation date.
(3) State expected life of facility or duration of purchase contract. The Company used Program Life (Years).
(4) Attributable capability and describe in the notes when such reductions are available, i.e.: at peak, all hours, on-peak hours, etc. The MWs reflected as of 2013.
(5) Reductions available during on-peak hours.
(6) Reductions available during all hours.
(7) This program was an outgrowth of the Company's current Distributed Generation/Load Curtailment Pilot for Large Non-residential customers.
(8) This program was an extension of the Company's current CFL price reduction program that began in October of 2007.
(9) Residential Bundle is comprised of the Residential Home Energy Check-Up Program, Residential Duct Testing & Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program.
(10) This program represents the extension of the Air Conditioner Cycling Program.
(11) This program represents the new Commercial HVAC Upgrade Program to be implemented in 2014 in Virginia and 2016 in North Carolina.
(12) This program represents the new Commercial Lighting Program to be implemented in 2014 in Virginia and 2016 in North Carolina.
(13) This program represents the extension of the Low Income Program.

APPENDIX 5F – DESCRIPTION OF FUTURE DSM PROGRAMS

Voltage Conservation

Target Class: All Classes
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2009 – 2038
NC Duration: 2016 – 2038

Program Description:
In 2009, the Company began an AMI Demonstration in areas of Virginia in order to fully understand the impacts of AMI. This program involves managing the voltage on the distribution circuits adjusting the load tap changing transformers and the circuit voltage regulators during off-peak load conditions, while maintaining the minimum voltage levels for customers at the end of the circuit. The objective of this program is to conserve energy by reducing voltage for residential, commercial and industrial customers served within the allowable band of 114 to 126 volts at the customer meter (for normal 120-volt service) during off-peak hours. The program is enabled through the deployment of AMI, which provides 15-minute voltage information from the meter.

Non-Residential Re-Commissioning Program

Target Class: Non-residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2015 – 2038
NC Duration: 2016 – 2038

Program Description:
In this Program, qualifying customers are provided an incentive to optimize the energy performance of their existing building and systems by identifying and implementing operational and maintenance improvements. These improvements include, but are not limited to, monitoring, troubleshooting, and adjusting the building's major energy-consuming systems and identifying opportunities to optimize equipment operation.

APPENDIX 5F Cont. – DESCRIPTION OF FUTURE DSM PROGRAMS

Non-Residential Custom Incentive Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2015 – 2038
NC Duration:	2016 – 2038

Program Description:
This Program will support non-residential customers in identifying and implementing site-specific and unique cost-effective retrofit and new construction energy efficiency opportunities through measures not addressed by other offerings. Calculated incentives will be paid based on measures implemented or equipment installed.

Residential Audit Program for Income Qualifying and Elderly Customers

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2015 – 2038
NC Duration:	2016 – 2038

Program Description:
This Program provides low income home owners and occupants and elderly customers with a free walk through audit, direct install measures, and recommendations for additional home energy improvements.

APPENDIX 5G – FUTURE PROGRAMS NON-COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Voltage Conservation Program	5,441	6,668	21,310	60,197	141,337	213,306	289,923	327,024	360,135	383,684	398,132	384,404	398,132	398,132	398,132	384,404
Non-Residential Re-Commissioning Program	0	0	81	324	715	1,120	1,893	2,024	2,050	2,077	2,065	1,974	1,741	1,373	963	272
Non-Residential Custom Incentive Program	0	0	4,995	19,013	37,637	57,524	77,479	85,555	87,021	87,906	88,774	89,627	90,467	91,299	92,132	92,967
New Residential Low Income Program	0	0	482	1,498	2,582	3,690	5,141	6,567	6,794	6,889	6,975	7,056	7,134	7,210	7,285	7,358
Total	5,441	6,668	26,868	81,032	182,272	275,640	374,436	421,170	456,001	480,555	495,945	483,060	497,475	498,015	498,512	485,000

APPENDIX 5H – FUTURE PROGRAMS COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Voltage Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Re-Commissioning Program	0	0	2	23	56	97	160	201	208	211	208	192	161	122	61	22
Non-Residential Custom Incentive Program	0	0	1,733	13,415	28,035	44,227	60,511	68,349	69,520	70,227	70,920	71,602	72,273	71,938	73,603	74,270
New Residential Low Income Program	0	0	76	590	1,170	1,773	2,387	2,702	2,765	2,801	2,835	2,867	2,898	2,929	2,959	2,988
Total	0	0	1,811	14,028	29,261	46,096	63,058	71,252	72,492	73,238	73,963	74,662	75,332	75,989	76,623	77,281

APPENDIX 5I – FUTURE PROGRAMS ENERGY SAVINGS
(MWh) (System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Voltage Conservation Program	27,845	34,124	109,049	319,048	723,264	1,091,548	1,483,621	1,733,243	1,842,918	1,963,421	2,037,359	2,037,359	2,037,359	2,037,359	2,037,359	2,037,359
Non-Residential Re-Commissioning Program	0	0	170	1,334	3,363	5,863	9,654	12,313	12,778	12,944	12,814	11,884	9,982	7,607	3,941	1,407
Non-Residential Custom Incentive Program	0	0	7,813	51,375	108,468	172,086	236,092	268,460	273,177	275,958	278,685	281,367	284,007	286,619	289,233	291,855
New Residential Low Income Program	0	0	576	3,628	7,410	11,354	15,378	17,663	18,099	18,339	18,560	18,771	18,977	19,177	19,372	19,565
Total	27,845	34,124	117,608	375,386	842,505	1,280,852	1,744,745	2,031,679	2,146,972	2,270,662	2,347,418	2,349,381	2,350,323	2,350,762	2,349,905	2,350,186

APPENDIX 5J– FUTURE PROGRAMS PENETRATIONS
(System-Level)

Programs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Voltage Conservation Program	77,273	77,273	403,167	1,045,252	1,615,081	2,173,332	2,703,791	2,703,791	2,703,791	2,703,791	2,703,791	2,703,791	2,703,791	2,703,791	2,703,791	2,703,791
Non-Residential Re-Commissioning Program[1]	0	0	6	24	53	83	140	150	152	154	149	133	105	77	21	13
Non-Residential Custom Incentive Program[1]	0	0	219	674	1,254	1,842	2,430	2,495	2,521	2,546	2,571	2,596	2,620	2,644	2,668	2,692
New Residential Low Income Program	0	0	2,047	6,357	10,962	15,661	20,454	21,202	21,499	21,769	22,022	22,267	22,507	22,740	22,968	23,194
Total	77,273	77,273	405,439	1,052,307	1,627,350	2,190,918	2,726,815	2,727,638	2,727,963	2,728,260	2,728,534	2,728,787	2,729,023	2,729,252	2,729,448	2,729,690

(1) Program penetrations have been adjusted for exempt customers.

APPENDIX 5K – PLANNED GENERATION INTERCONNECTION PROJECTS

Line Terminal	PJM Queue	Line Voltage (kV)	Line Capacity (MVA)	Interconnection Cost (Million $)	Target Date	Location
North Anna – Ladysmith*	Q-65	500	4,300	48	Apr-18	VA

*Subject to change based on receipt of applicable regulatory approval(s).

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 5L – LIST OF PLANNED TRANSMISSION LINES

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #65 Uprate (Garner - Lancaster)	115	217	Sep-13	VA
Lexington - Cloverdale Line # 566 Uprate	500	4,000	Dec-13	VA
Line 270 - Burke to Sideburn - Install 2nd UG 230kV Cable	230	586	Mar-14	VA
N 301 Industrial Park 115kV DP (HEMC)	115	261	Apr-14	NC
Hollymead Tap Rebuild	230	1,047	May-14	VA
Dooms to Bremo 230kV Transmission Line Rebuild	115	240	May-14	VA
Dahlgren Substation 230kV Line (Loop Line #2076)	230	1,047	May-14	VA
Line #69 Uprate	115	263	May-14	VA
Line #148 Uprate	115	162	May-14	VA
Glebe-Radnor Heights-Ballston 230kV UG Line	230	354	Jun-14	VA
Line #100 Rebuild between Chesterfield - Harrowgate	115	398	Jun-14	VA
Northwest to Lakeside 230kv Line	230	1,047	Jun-14	VA
Uprate Line #575 (Ladysmith - North Anna)	500	3428	Jun-14	VA
Cannon Branch to Cloverhill - New 230kV Line	230	1,047	Jul-14	VA
Line #90 Rebuild	115	262	Oct-14	NC
Convert Line 64 to 230kV and Install 230kV Capacitor Bank at Winfall	230	775 (#2131) 840(#2126)	Dec-14	NC
Rebuild Line #551 (Mt Storm - Doubs)	500	4,334	Dec-14	VA
Line #296 Reconductor Halifax to Dominion/Progress Dividing Line	230	712	Feb-15	VA/NC
Uprate Line 2022 - Possum Point to Dumfries Substation	230	705	May-15	VA
Line #262 Rebuild (Yadkin - Chesapeake EC) Line #2110 Reconductor (Suffolk - Thrasher)	230 230	1,047 1195	May-15	VA
Shawboro – Aydlett Tap 230kV Line	230	751	May-15	NC
Cloverhill to Liberty - New 230kV Line	230	1,047	May-15	VA
Surry - Skiffes Creek 500 kV Line	500	4,325	May-15	VA
Skiffes Creek - Whealton 230 kV Line	230	1,047	May-15	VA
Line #2020 Rebuild Winfall - Elizabeth City	230	1,047	Jun-15	NC
Yadkin - Chesapeake Increase 115 kV Capacity	115	398	Jun-15	VA
Line #22 Rebuild Kerr Dam - Eatons Ferry	115	262	Jun-15	VA/NC
Line #30 Rebuild (Altivista to Skimmer)	115	239	Jun-15	VA
2nd 230kV Line Harrisonburg to Endless Caverns	230	1,047	Jun-15	VA
Line #17 Uprate Shockoe - Northeast and Terminate Line #17 at	115	231	Jul-15	VA
Line #222 Uprate from Northwest to Southwest	230	706	Jul-15	VA
Line #201 Rebuild	230	1,200	Nov-15	VA
Rebuild Dooms to Lexington 500 kV Line	500	4,000	Dec-15	VA
Burton Switching Station and 115 kV Line to Oakwood	115	233	Dec-15	VA
Line #2090 Uprate	230	1,195	May-16	VA
Line #2032 Uprate (Elmont - Four Rivers)	230	1,195	May-16	VA
Loudoun – Pleasant View Line #558 Rebuild	500	4,000	May-16	VA
Line #2104 Reconductor and Upgrade	230	1,047	May-16	VA
Rebuild Line #2027 (Bremo - Midlothian)	230	1,047	May-16	VA
Line #11 - Rebuild or Reconductor from Gordonsville to Somerset	115	353	May-16	VA
Line #33 Rebuild and Halifax 230kV Ring Bus	115	353	Jun-16	VA
Line #22 Rebuild Carolina - Eatons Ferry	115	262	Jun-16	NC
Line #54 Reconductor Carolina - Woodland	115	306	Jun-16	NC
New 230kV Line Dooms to Lexington	230	1,047	Jun-16	VA
*Network Line 2086 from Warrenton	230	1,047	May-17	VA
*Idylwood to Liberty Crossing – New 230kV Line and Liberty Crossing	230	1,047	May-17	VA
Line #69 Uprate Reams DP to Purdy	115	300	Jun-17	VA
Line #553 (Cunningham to Elmont) Rebuild and Uprate	500	4,000	Dec-17	VA
* Rebuild Line #4 Bremo to Cartersville	115	388	May-18	VA
Convert Line #91 and Line #39 to 230kV Operation	230	1,047	May-19	VA
* Line #47 Rebuild	115	353	May-19	VA
* Remington to Oak Green 230kV line, 230-115kV Tx at Oak Green	230	1,047	May-19	VA
* Rebuild Line #119 from Grottoes to Merck	115	353	May-19	VA
Rebuild Mt Storm - Valley 500 kV Line	500	4,000	Dec-20	VA
* Line #38 Uprate Kerr - Boydton DP	115	353	Jun-21	NC
Rebuild Dooms to Valley 500 kV Line	500	4,000	Jun-21	VA

[redacted]

Note: Asterisk reflects planned transmission addition subject to change based on inclusion in future PJM RTEP and/or receipt of applicable regulatory approval(s).

APPENDIX 6A – RENEWABLE RESOURCES

Company Name: Virginia Electric and Power Company

RENEWABLE RESOURCE GENERATION (GWh)

Schedule 11

Resource Type[1]	Unit Name	C.O.D.[2]	Build/Purchase/Convert[3]	Life/ Duration[4]	Size MW[5]	2010 (ACTUAL)	2011 (ACTUAL)	2012 (ACTUAL)	2013	2014 (PROJECTED)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hydro																								
	Cushaw Hydro	Jan-30	Build	60	2	10	5	9	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Gaston Hydro	Feb-63	Build	60	220	341	199	175	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289
	North Anna Hydro	Dec-87	Build	60	1	2	2	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	Sep-55	Build	60	95	338	165	159	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290
Sub-total					318	692	391	345	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Solar																								
	Solar NUG 2015	Jan-15	Purchase	15	50	-	-	-	-	-	102	101	100	100	99	99	98	97	96	96	95	94	93	93
	Solar Partnership Program	2013-2015[8]	Build	15	24	-	-	-	3	12	24	31	31	31	31	31	31	31	31	31	31	31	31	28
Sub-total					74	-	-	-	3	12	126	132	131	130	130	129	128	128	127	126	125	125	124	121
Biomass[6]	Unit Name																							
	Pittsylvania	Jun-94	Purchase	60	83	413	393	341	342	304	299	463	564	581	592	613	615	632	644	647	650	647	650	645
	Virginia City Hybrid Energy Center[7]	Apr-12	Build	60	6	-	-	-	43	121	189	246	269	350	370	473	448	437	468	446	429	467	440	425
	Altavista	Feb-92	Convert	30	51	-	-	-	239	394	419	412	419	411	419	412	419	411	419	412	419	411	419	412
	Southampton	Mar-92	Convert	30	51	-	-	-	76	394	419	420	419	419	419	420	419	419	419	395	419	419	419	420
	Hopewell	Jul-92	Convert	30	51	-	-	-	147	411	394	412	419	412	412	413	412	412	412	413	412	412	412	413
	Covanta Fairfax	-	Purchase	-	63	560	600	580	319	407	178	-	-	-	-	-	-	-	-	-	-	-	-	-
	Energy Extraction Partners	-	Purchase	20	15	-	-	-	-	-	83	112	112	112	112	112	111	112	111	112	112	112	112	111
	Economic Power & Steam Generation	-	Purchase	15	20	-	-	-	-	-	149	149	148	149	149	149	149	149	149	149	149	148	149	149
Sub-total					320	1,651	1,322	1,148	1,188	2,030	2,148	2,214	2,370	2,433	2,471	2,582	2,573	2,570	2,621	2,574	2,588	2,618	2,601	2,574
Total Renewables					712	2,343	1,713	1,493	1,785	2,639	2,871	2,942	3,097	3,180	3,197	3,317	3,298	3,294	3,345	3,296	3,310	3,337	3,321	3,291

(1) Per definition of Va. Code § 56-576.
(2) Commercial Operation Date.
(3) Company built, purchased or converted.
(4) Expected life of facility or duration of purchase contract.
(5) Net Summer Capacity for Biomass and Hydro, Nameplate for Solar and Wind.
(6) Excludes contracted 25 MW BTMG biomass capacity.
(7) Duel fired coal & biomass.
(8) In 2013, 2014, 2015.

APPENDIX 6B – POTENTIAL SUPPLY-SIDE RESOURCES

Company Name: Virginia Electric and Power Company **Schedule 15b**

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Nameplate
Generic CC 3x1 2027	N/A	Intermediate/ Baseload	Natural Gas-CC	N/A	1,375	1,375
Generic CT 2021	N/A	Peak	Natural Gas-Turbine	N/A	457	457
Generic CT 2022	N/A	Peak	Natural Gas-Turbine	N/A	457	457
Generic CT 2023	N/A	Peak	Natural Gas-Turbine	N/A	457	457

(1) Commercial Operation Date.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED
APPENDIX 6C – SUMMER CAPACITY POSITION

Company Name: Virginia Electric and Power Company

UTILITY CAPACITY POSITION (MW)

Schedule 16

	(ACTUAL)									(PROJECTED)									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Existing Capacity																			
Conventional	15,964	16,531	17,153	17,144	17,132	16,130	16,085	16,012	16,006	15,921	15,915	15,915	15,915	15,915	15,915	15,915	15,915	15,915	15,915
Renewable	400	400	400	560	572	584	590	596	602	608	614	614	614	614	614	614	614	614	614
Total Existing Capacity	16,364	16,931	17,553	17,704	17,704	16,714	16,655	16,608	16,608	16,529	16,529	16,529	16,529	16,529	16,529	16,529	16,529	16,529	16,529
Generation Under Construction																			
Conventional	-	-	-	-	-	1,337	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712	2,712
Renewable	-	-	-	1	4	7	7	7	7	7	7	7	7	7	7	7	7	7	6
Total Planned Construction Capacity	-	-	-	1	4	1,344	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,718
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Development Capacity	-	-	-	-	-	-	-	-	-	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	457	914	1,371	1,371	1,371	1,371	2,746	2,746
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Potential New Capacity	-	-	-	-	-	-	-	-	-	-	-	457	914	1,371	1,371	1,371	1,371	2,746	2,746
Other (NUG)	1,749	1,747	1,747	1,747	1,747	1,402	1,286	461	480	315	271	271	53	53	53	53	53	52	52
Unforced Availability	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Generation Capacity	18,113	18,679	19,300	19,453	19,456	19,460	20,660	19,608	19,808	20,936	20,894	21,351	21,590	22,047	22,047	22,047	22,047	23,422	23,420
Existing DSM Reductions																			
Demand Response	9	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
Conservation/Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions[1]	9	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
Approved DSM Reductions																			
Demand Response[4]	14	42	65	101	129	151	175	203	228	240	243	244	245	247	249	252	254	256	259
Conservation/Efficiency[2][4]	19	33	40	48	67	94	123	137	143	142	132	122	115	114	114	115	115	115	116
Total Approved DSM Reductions	33	75	105	148	196	246	298	340	371	382	375	366	360	361	364	366	369	371	374
Future DSM Reductions																			
Demand Response[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency[2]	-	-	-	-	2	19	49	83	121	148	158	160	161	163	164	166	167	169	170
Total Future DSM Reductions	-	-	-	-	2	19	49	83	121	148	158	160	161	163	164	166	167	169	170
Total Demand-Side Reductions[1]	33	75	105	148	198	264	348	423	492	530	532	526	522	523	528	532	536	540	545
Net Generation & Demand-side	18,146	18,753	19,406	19,601	19,654	19,724	21,008	20,231	20,300	21,466	21,427	21,877	22,112	22,570	22,575	22,579	22,583	23,962	23,965
Capacity Sale[3]	[redacted]							-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
Capacity Purchase[3]								345	523	1	1	1	1	1	103	421	748	1	36
Capacity Adjustment[3]								-	-	-	-	-	-	-	-	-	-	-	-
Capacity Requirement or PJM Capacity Obligation	[redacted]							20,155	20,359	20,979	20,937	21,396	21,836	22,085	22,199	22,520	22,848	23,478	23,514
Net Utility Capacity Position	[redacted]							145	323	-199	-199	-199	-199	-199	-97	221	548	-199	-164

(1) Existing DSM programs are included in the load forecast.

(2) Efficiency programs are not part of the Company's calculation of capacity.

(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.

(4) Values for 2010, 2011 and 2012 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.

CONFIDENTIAL INFORMATION REDACTED
APPENDIX 6D – CONSTRUCTION FORECAST

Company Name: Virginia Electric and Power Company

CONSTRUCTION COST FORECAST (Thousand Dollars)

Schedule 17

(PROJECTED)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. New Traditional Generating Facilities[2]																
a. Construction Expenditure (Not AFUDC)[2]	[redacted]															
b. AFUDC[1]																
c. Annual Total																
d. Cumulative Total																
II. New Renewable Generating Facilities																
a. Construction Expenditure (Not AFUDC)	[redacted]															
b. AFUDC[1]																
c. Annual Total																
d. Cumulative Total																
III. Other Facilities																
a. Transmission	[redacted]															
b. Distribution																
c. Energy Conservation & DR[3]																
d. Other																
e. AFUDC																
f. Annual Total																
g. Cumulative Total																
IV. Total Construction Expenditures																
a. Annual	[redacted]															
b. Cumulative																
V. % of Funds for Total Construction Provided from External Financing	[redacted]															

(1) Does not include Construction Work in Progress.

(2) The construction expenditure includes both modeled and budgeted expenditures.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED
APPENDIX 6E – CAPACITY POSITION

Company Name: Virginia Electric and Power Company — Schedule 4
POWER SUPPLY DATA

	(ACTUAL)								(PROJECTED)										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. Capability (MW)																			
1. Summer																			
a. Installed Net Dependable Capacity(1)	18,364	18,931	17,553	17,705	17,708	18,058	19,374	19,327	19,327	20,623	20,623	21,080	21,537	21,994	21,994	21,994	21,994	23,369	23,368
b. Positive Interchange Commitments(2)	1,749	1,747	1,747	1,747	1,747	1,402	1,286	481	480	315	271	271	53	53	53	53	53	52	52
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	74	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	9	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
e. Demand Response - Approved(6)	14	42	65	101	129	151	175	203	228	240	243	244	245	247	249	252	254	256	259
f. Demand Response - Future(5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Capacity Sale(3)	[redacted]							-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
h. Capacity Purchase(3)								345	523	1	1	1	1	1	103	421	748	1	38
i. Capacity Adjustment(3)								-	-	-	-	-	-	-	-	-	-	-	-
j. Total Net Summer Capability(4)								20,155	20,359	20,979	20,937	21,396	21,838	22,095	22,199	22,520	22,649	23,478	23,514
2. Winter																			
a. Installed Net Dependable Capacity(1)	-	-	-	20,368	20,105	19,179	20,582	20,502	20,432	21,872	21,834	22,297	22,760	23,223	23,223	23,223	23,223	24,732	24,732
b. Positive Interchange Commitments(2)	-	-	-	1,940	1,940	2,061	1,482	1,481	554	553	388	340	117	117	116	115	115	114	114
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	77	77	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response(5)	-	-	14	26	34	37	41	49	55	58	59	60	61	62	63	64	65	66	67
e. Demand Response-Existing(6)	7	8	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5
f. Total Net Winter Capability(4)	-	-	-	22,334	22,079	21,277	22,105	22,032	21,041	22,483	22,279	22,697	22,938	23,402	23,402	23,403	23,403	24,912	24,913

(1) Net Seasonal Capability.
(2) Includes only firm commitments from Non-Utility Generation.
(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.
(4) Does not include Cold Reserve Capacity and Behind-the-Meter Generation MWs.
(5) Values for 2010, 2011 and 2012 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.
(6) Included in the winter capacity forecast.

E-100 Sub 137

NC IRP ADDENDUM 1

Public Redacted Version

DOMINION NORTH CAROLINA POWER
2013 REPS COMPLIANCE PLAN

Pursuant to N.C.G.S. § 62-133.8 and North Carolina Utilities Commission ("NCUC" or "Commission") Rule R8-67(b), Virginia Electric & Power Company d/b/a Dominion North Carolina Power ("DNCP" or the "Company") submits its annual Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plan. The REPS Compliance Plan covers the current calendar year (2013) and immediately subsequent two calendar years (2014-2015) (the "Planning Period"). The Company also presents REPS compliance information for Town of Windsor during the Planning Period.[1] This North Carolina REPS Compliance Plan is an addendum to the Company's 2013 Integrated Resource Plan update ("2013 Plan").

As indicated in the Company's REPS Compliance Report filed on August 29, 2013, the Company has satisfied all 2012 REPS compliance obligations.

1.1 RENEWABLE ENERGY REQUIREMENTS

An overview of North Carolina's REPS requirements and Virginia's Renewable Energy Portfolio Standard ("RPS") goals are provided in Chapter 4, Section 4.3.1 of the Company's 2013 Plan.

1.2 COMPLIANCE PLAN

In accordance with Rule R8-67(b)(i), the Company describes its planned actions to comply with N.C.G.S. 62-133.8 (b),(c),(d),(e), and (f) for each year.

<u>The Company</u>

During the Planning Period, DNCP plans to meet its statutory annual REPS obligations, as modified by the Commission[2], through the use of renewable energy certificates ("RECs")[3]; energy efficiency ("EE") savings and new company-generated renewable energy where economically feasible.

---

[1] Town of Windsor is a wholesale customer of the Company, for which DNCP provides REPS compliance services.

[2] The Commission issued an Order on November 29, 2012, which eliminated the Swine Waste Set-Aside for 2012 and delayed the Poultry Waste Set-Aside until 2013, in Docket No. E-100, Sub 113. *Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief,* Docket No. E-100, Sub 113 (Nov. 29, 2012) ("Nov. 29, 2012 Delay Order").

[3] For planning purposes, Dominion notes that the Company has unique flexibility to use out-of-state RECs for REPS compliance. *Order on Dominion's Motion for Further Clarification*, Docket No. E-100, Sub 113 (Sept. 22, 2009) (holding that the meaning of N.C.G.S. § 62-133.8(b)(2)(e) is to allow DNCP to achieve up to 100% REPS general obligation and set-aside compliance using out-of-state RECs).

Figure 1.2.1 summarizes DNCP's REPS compliance requirements and strategy for the Planning Period.

Figure 1.2.1 2013-2015 COMPANY'S REPS COMPLIANCE PLAN SUMMARY

	2013	2014	2015
Baseline Sales Forecast (MWh)	4,174,888	4,029,770	4,085,517
NC Total REPs Requirement %	3%	3%	6%
Total REPS Target (MWh)[1]	123,436	125,247	241,787
NC Total Solar Target %	0.07%	0.07%	0.14%
Total Solar Target (MWh)[1]	2,881	2,923	5,642
NC Total Swine Target %	0.07%	0.07%	0.14%
Total Swine Target (MWh)[1]	2,881	2,923	5,642
NC Total Poultry Target %	3.22%	2.91%	2.90%
Total Poultry Target (MWh)[1,2]	5,474	20,370	26,100
General REPS Requirement (net of Solar, Swine and Poultry) (MWh)	112,200	99,031	204,403
Energy Efficiency (MWh)[3]	21,488	25,059	30,101
Company Generated Renewables (MWh)[4]	32,910	80,286	97,419

Notes: (1) 2013 target is based on actual 2012 retail sales of 4,114,540 MWh. 2014-2015 targets are based on baseline retail sales forecasts. The total target is the product of the previous year's baseline load and the current year target percentage. (2) Calculation may not equal due to rounding. (3) The EE savings represents a projected system allocation. It may be more appropriate to use specific EE savings attributable to North Carolina customers. (4) Company Generated Renewables (MWh) are the North Carolina jurisdictional allocation.

As shown in Figure 1.2.1, the Company's requirements in the Planning Period include the solar energy resource requirement ("Solar Set-Aside"), swine waste resource requirement ("Swine Set-Aside"), and poultry waste resource requirement ("Poultry Set-Aside"). In addition, the Company must also ensure that, in total, the RECs that it produces or procures, combined with EE savings, is an amount equivalent to three percent (3%) of its prior year retail sales in compliance years 2013 and 2014, and six percent (6%) in 2015 ("Total Obligation").[4]

[4] DNCP refers to its Total Obligation, net of the Solar, Swine, and Poultry Set-Aside requirements, as its General Requirement ("General Requirement").

Town of Windsor

Planned REPS compliance for Town of Windsor during the Planning Period is outlined in Figure 1.2.2.

Figure 1.2.2 2013-2015 TOWN OF WINDSOR REPS COMPLIANCE PLAN SUMMARY

	2013	2014	2015
Baseline Sales Forecast (MWh)	48,300	50,500	51,000
NC Total REPs Requirement %	3%	3%	6%
Total REPS Target (MWh)[1]	1,419	1,449	3,030
NC Total Solar Target %	0.07%	0.07%	0.14%
Total Solar Target (MWh)[1]	34	34	71
NC Total Swine Target %	0.07%	0.07%	0.14%
Total Swine Target (MWh)	34	34	71
NC Total Poultry Target %[1]	0.04%	0.04%	0.04%
Total Poultry Target (MWh)[1]	68	280	360
General REPS Requirement (net of Solar, Swine and Poultry) (MWh)	1,283	1,101	2,528

Notes: (1) 2013 target is based on actual 2012 retail sales of 47,275 MWh reported by Town of Windsor to DNCP. 2014-2015 targets are based on forecasts reported by Town of Windsor to DNCP. The total target is a product of the previous year's baseline retail sales and the current year target percentage.

Solar Set-Aside

Pursuant to N.C.G.S. § 62-133.8(d), the Company must produce or procure solar RECs equal to a minimum of seven hundredths of one percent (0.07%) of the prior year's total electric power in megawatt-hours ("MWh") sold to retail customers in North Carolina in 2013 and 2014, and fourteen hundredths of one percent (0.14%) in 2015.

Based on the Company's actual retail sales in 2012, the Solar Set-Aside is approximately 2,881 RECs in 2013. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 2,923 RECs and 5,642 RECs in 2014 and 2015, respectively.

The Company's Solar Set-Aside compliance strategy is consistent with DNCP's plan from the previous years, as described herein. Specifically, DNCP plans to buy unbundled solar RECs. The Company has purchased, or entered into contracts to purchase, solar RECs for DNCP's compliance with N.C.G.S. § 62-133.8(d) through 2014. These contracts will provide enough solar RECs to satisfy DNCP's compliance for the years 2013 and 2014 and approximately 35% of DNCP's requirements for 2015 through 2017. The Company has also executed contracts with solar facilities located in North Carolina that will satisfy the in-state portion of Town of Windsor's compliance requirements for 2013 and 2014. DNCP continues to evaluate opportunities to purchase both in-state and out-of-state solar RECs, and will continue to make all reasonable efforts to satisfy DNCP's and Town of Windsor's solar set-aside requirements during the Planning Period.

Swine Set-Aside

Pursuant to N.C.G.S. § 62-133.8(e), for calendar years 2013, 2014, and 2015, at least seven hundredths of one percent (0.07%) of prior year total retail electric power sold in aggregate by electric power suppliers in North Carolina must be supplied by energy derived from swine waste. As the Company's share of the State's total retail megawatt-hour sales is approximately 3.22 percent, the Company's Swine Set-Aside is estimated to be 2,881 RECs in 2013, 2,923 RECs in 2014, and 5,642 RECs in 2015.

In an ongoing effort to comply with the Swine Waste Set-Aside, the Company has attempted to obtain swine waste RECs from facilities in Virginia, North Carolina and across the continental United States. The Company has also contacted digester owners and operators, hog producers and REC marketers/brokers to determine if any swine waste RECs are available for purchase. As a result of its search efforts for swine waste RECs in the marketplace and across the Nation, the Company has determined that swine waste-to-energy technology remains a relatively new technology and may not yet be commercially viable. Furthermore, a ready market for swine waste RECs has not yet developed. Based on this assessment, the Company has concluded that joining the collaborative Swine Waste REC Buyers Group was, and still is, the most cost effective and prudent approach to meet the Company's Swine Waste Set-Aside requirements. The Company joined the Swine Waste REC Buyers Group and continues to be an active participant in the group's efforts.

The Swine Waste REC Buyers Group executed seven (7) long-term contracts with a number of swine waste-to-energy developers. These contracts were expected to meet the Company's Swine Waste Set-Aside requirements until 2015 and a significant portion of ongoing Swine Waste Set-Aside requirements thereafter. Four (4) of these swine waste REC contracts were terminated in May and June 2012 due to consistent failure by the counter-party developers to meet project milestones and to demonstrate progress toward commercial operation. Because of these terminations, the Company is now conducting a new search for other swine waste REC suppliers in North Carolina and across the Nation. DNCP has spent considerable time and effort in an attempt to locate operational swine waste digesters in the continental United States. This exhaustive search has identified only one small potential supplier. The Company has initiated contract negotiations with this supplier.

In sum, DNCP continues to evaluate all potential opportunities to purchase both in-state and out-of-state swine RECs, and will continue to make all reasonable efforts to satisfy DNCP's and Town of Windsor's Swine Set-Aside requirements during the Planning Period.

Poultry Set-Aside

Pursuant to N.C.G.S. § 62-133.8(f) and the November 29, 2012 Delay Order, for calendar years 2013, 2014, and 2015, at least 170,000 MWhs, 700,000 MWhs, and 900,000 MWhs, respectively, of the prior year's total electric power sold to retail electric customers in the State or an equivalent amount of energy shall be produced or procured each year by poultry waste, as defined per the Statute and additional clarifying Orders. As the Company's retail sales share of the State's total retail megawatt-hour sales is approximately 3.22%, the Company's Poultry Set-Aside is estimated to be 5,474 RECs in 2013, 20,370 RECs in 2014, and 26,100 in 2015.

DNCP has worked actively and diligently to comply with its Poultry Set-Aside requirements for the Company and Town of Windsor. The Company, after searching the REC market for available in-state RECs, concluded that joining the Poultry Waste REC Buyers Group was the most prudent way to meet Town of Windsor's Poultry Set-Aside requirement.

The Poultry Waste REC Buyers Group has executed two (2) long-term poultry waste contracts and the Company, as a part of this group, has executed two (2) long-term contracts to satisfy Town of Windsor's in-state Poultry Set-Aside requirements. These long-term contracts will not yield any RECs until 2017. In an attempt to locate and purchase poultry RECs for compliance before 2017, the Company joined with the Poultry Waste REC Buyers Group in requesting Commission approval for a RFP in Docket E-100 Sub 113. At this time, the Company does not believe it can meet Town of Windsor's in-state poultry waste requirement for 2013-2015.

The Company has also continued to search for opportunities to purchase poultry waste RECs in North Carolina and throughout the continental United States. These efforts yielded two poultry waste REC contracts with enough volume to comply with both DNCP's and Town of Windsor's out-of-state requirements for years 2013, 2014 and to partially satisfy the 2015 requirement.

General REPS Requirements Net of Solar, Swine and Poultry

Pursuant to N.C.G.S. § 62-133.8(d), DNCP is required to comply with its Total Obligation in the Planning Period by submitting for retirement a total volume of RECs equivalent to three percent (3%) of retail sales in North Carolina in the prior year in 2013 and 2014 and six percent (6%) in 2015. This equates to approximately 123,436 RECs in 2013, 125,247 RECs in 2014, and 241,787 RECs in 2015. This General Requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is estimated to be 112,200 RECs in 2013, 99,031 RECs in 2014, and 204,403 in 2015. The various resource options available to the Company to meet the General Requirement are discussed below, as well as the Company's plan to meet the General Requirement with these resources.

The Company plans to comply with the General Requirement using a combination of EE savings generated by the Company's portfolio of approved North Carolina EE programs; purchasing out-of-state wind RECs; using company-generated new renewable energy resources; and, for Town of Windsor, using its Southeastern Power Administration ("SEPA") allocation of hydroelectric RECs. .

In 2010, DNCP obtained Commission approval to deploy its first phase of EE Programs in North Carolina, as part of its broader efforts to integrate demand side management and EE resource options across the Company's system. Approved Phase I programs included the Commercial Lighting Program; Commercial HVAC Upgrade Program; Residential Lighting Program; Low Income Program. Very recently, on August 20, 2013, the Company also filed Applications to deploy six "Phase II" EE Programs in North Carolina as well as to reinitiate its currently suspended Commercial Lighting Program and Commercial HVAC Upgrade Program in North Carolina only. Pending Phase II EE Programs include the Non-residential Energy Audit Program; Non-residential Duct Testing and Sealing Program; Residential Home Energy Check-Up Program; Residential Duct Testing & Sealing Program; Residential Heat Pump Tune-Up Program; and Residential Heat Pump Upgrade Program. Pursuant to Commission Rule R8-67(b)(1)(iii), the Company has presented in Figure 1.4.1 below these EE measures that it plans to use toward REPS compliance, including projected impacts.

The Company's 2013 Plan includes in the Preferred Plan, beginning in 2014, company-generated new renewable energy from biomass fuel co-firing at the Company's Virginia City Hybrid Energy Center (VCHEC), which commenced commercial operations in 2012, as well as biomass fuel conversions at the Altavista, Hopewell and Southampton power stations scheduled to commence commercial operations in the second half of 2013.[5] The Company intends to sell RECs generated at these facilities in PJM Tier 1 markets at a significant premium to the out-of-state general RECs the Company is purchasing for compliance.

[5] On February 7, 2013, DNCP filed its Rule R8-66 REPS Facility Registration Statement for VCHEC with the Commission in Docket No. E-22, Sub 489. The Company will file Rule R8-66 registration statements for the Altavista, Hopewell and Southampton Power Stations prior to relying on these facilities for REPS compliance.

1.3 REC CONTRACTS

In accordance with Rule R8-67(b)(ii), the Company provides a list of executed contracts to purchase renewable energy certificates.

As mentioned in the previous section, the Company has purchased wind, biomass, poultry waste and solar RECS and entered into long-term poultry waste, swine waste and solar REC contracts to comply with N.C.G.S. § 62-133.8(b), (d), (e), and (f). Figures 1.3.1 through 1.3.4 provide summaries of DNCP's REC purchase contracts. The Company will use a portion of out-of-state REC purchases to satisfy 25% of Town of Windsor's compliance requirements.

CONFIDENTIAL INFORMATION REDACTED

Figure 1.3.1 Solar REC Purchase Contract Summary[1]

	Total Volume	Volume / Year	Term	Price / MWh	Total Expense
[redacted]	15,000	2,500	2012-2017	[redacted]	[redacted]
[redacted]	729	729	2010	[redacted]	[redacted]
[redacted]	392	392	2009	[redacted]	[redacted]
[redacted]	4	4	2010	[redacted]	[redacted]
[redacted]	4	4	2010	[redacted]	[redacted]
[redacted]	50	50	2011	[redacted]	[redacted]
[redacted]	2,000	1,000	2010-2011	[redacted]	[redacted]
[redacted]	40	40	2012	[redacted]	[redacted]
[redacted]	24	24	2012	[redacted]	[redacted]
Total Volume	**18,243**			**Total Expense**	[redacted]

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2011 and 2012 for future compliance purposes. (2) Contracts for Town of Windsor compliance.

CONFIDENTIAL INFORMATION REDACTED

Figure 1.3.2 Poultry Waste REC Purchase Contract Summary[1,2]

	Total Volume	Volume / Year	Term	Price / MWh	Total Expense
[redacted]	30,000	Varies	2013-2014	[redacted]	[redacted]
[redacted]	25,000	25,000	2012	[redacted]	[redacted]
Total Volume	55,000			Total Expense	[redacted]

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2011 and 2012 for future compliance purposes. (2) The Company has also executed two (2) long-term contracts with Poultry Power USA for in-state RECs for Town of Windsor compliance.

CONFIDENTIAL INFORMATION REDACTED

Figure 1.3.3 General REC Purchase Contract Summary[1]

	Total Volume	Volume / Year	Term	Price / MWh	Total Expense
[redacted]	30,000	30,000	2012	[redacted]	[redacted]
[redacted]	20,000	20,000	2012	[redacted]	[redacted]
[redacted]	20,000	20,000	2012	[redacted]	[redacted]
[redacted]	1,000	1,000	2012	[redacted]	[redacted]
[redacted]	42,400	42,400	2012	[redacted]	[redacted]
[redacted]	25,600	25,600	2012	[redacted]	[redacted]
[redacted]	25,000	25,000	2012	[redacted]	[redacted]
Total Volume	164,011			Total Expense	[redacted]

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2012 for future compliance purposes. (2) Contract for Town of Windsor compliance.

CONFIDENTIAL INFORMATION REDACTED

Figure 1.3.4 Swine Waste REC Purchase Contract Summary

	Total Volume	Term	Price / MWh²	Total Expense
[redacted]	6,480	20	[redacted]	[redacted]
[redacted]	16,200	20	[redacted]	[redacted]
[redacted]	19,420	20	[redacted]	[redacted]
Total Volume	**42,100**		**Total Expense**	[redacted]

Notes: Contract counterparties and prices are confidential. (1) Reduced volumes in first year of contract. Volume / Year shows first full calendar year production. (2) Price escalates annually. Prices given are for initial year. **[Begin Confidential]** [redacted] **[End Confidential]**.

1.4 ENERGY EFFICIENCY PROGRAMS

In accordance with Rule R8-67(b)(iii), the Company provides a list of planned or implemented energy efficiency measures, including a brief description of the measure and projected impacts.

The Company intends to apply EE savings to meet the NC REPS requirements as permitted by law. Figure 1.4.1 lists the potential EE programs and resulting savings based on a projected system allocation. Depending on the outcome of the evaluation of operating EE programs exclusively in North Carolina, it may be more appropriate to use specific EE savings attributable to North Carolina customer participation. A brief description of these EE programs can be found in Section 3.2 of the 2013 IRP. The Company also intends to seek approval to deploy additional North Carolina EE programs in the future.

Figure 1.4.1 SAVINGS (MWh) NORTH CAROLINA ENERGY EFFICIENCY PROGRAMS

	2013	2014	2015
Commercial HVAC Upgrade Program[1]	356	356	356
Commercial Lighting Program[1]	5,899	5,899	5,899
Low Income Program	366	446	485
Residential Lighting Program	13,473	13,473	13,473
Non-residential Energy Audit Program[2]	270	1,062	2,457
Non-residential Duct Testing and Sealing Program[2]	279	913	1,747
Residential Home Energy Check-Up Program[2]	38	128	246
Residential Duct Testing & Sealing Program[2]	40	140	272
Residential Heat Pump Tune-Up Program[2]	540	1,829	3,562
Residential Heat Pump Upgrade Program[2]	228	815	1,605
Energy Efficiency Total[3]	**21,488**	**25,059**	**30,101**

Notes: (1) Programs proposed to be offered in North Carolina only. (2) Programs filed August 20, 2013, with Commission and pending approval; and (3) Energy Efficiency savings represent a projected system allocation. For REPS reporting and compliance purpose, DNCP will rely upon EE savings achieved by North Carolina customers.

1.5 RETAIL SALES & CUSTOMER ACCOUNTS

In accordance with Rule R8-67(b)(iv), the Company states the projected Company's North Carolina retail sales and year-end number of customer accounts by customer class for each year.

<u>The Company</u>

Figure 1.5.1 summarizes the Company's North Carolina retail sales and Figure 1.5.2 summarizes the year-end number of customer accounts by customer class for each year of the Planning Period.

Figure 1.5.1 COMPANY'S NORTH CAROLINA RETAIL SALES[1]

Year	Residential Sales (MWh)	Commercial Sales (MWh)[2]	Industrial Sales (MWh)	Total Sales (MWh)
2013 (projected)	1,638,118	1,025,774	1,510,995	4,174,887
2014 (projected)	1,604,849	949,426	1,475,495	4,029,770
2015 (projected)	1,626,192	976,678	1,482,647	4,085,517

Notes: (1) Excludes Town of Windsor's wholesale customer load.

Figure 1.5.2 COMPANY'S NORTH CAROLINA CUSTOMER ACCOUNTS[1]

Year	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
2013 (projected)	106,898	18,511	53	125,462
2014 (projected)	108,430	18,719	53	127,202
2015 (projected)	110,166	18,951	53	129,170

Notes: (1) Customer account totals are year-end forecasts. These differ slightly from Appendix 2F in the 2013 IRP which are average yearly amounts. Forecasts do not include Rate Schedules 1DF, 1W, 7, 26, 30T.

Town of Windsor

Figure 1.5.3 summarizes Town of Windsor's retail sales and Figure 1.5.4 summarizes the year-end number of customer accounts by customer class for each year of the Planning Period.

Figure 1.5.3 TOWN OF WINDSOR'S RETAIL SALES[1]

Year	Residential Sales (MWh)	Commercial Sales (MWh)	Industrial Sales (MWh)	Total Sales (MWh)
2013 (projected)	18,500	28,000	1,800	48,300
2014 (projected)	20,000	28,500	2,000	50,500
2015 (projected)	20,000	29,000	2,000	51,000

Note: (1) Sales are year-end forecasts reported by Town of Windsor to DNCP.

Figure 1.5.4 TOWN OF WINDSOR'S CUSTOMER ACCOUNTS[1]

Year	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
2013 (projected)	1,400	410	1	1,811
2014 (projected)	1,450	415	1	1,866
2015 (projected)	1,450	415	1	1,866

Notes: (1) Customer account totals are year-end forecasts reported by Town of Windsor to DNCP.

1.6 AVOIDED COST RATES

In accordance with Rule R8-67(b)(v), the Company provides the following statement regarding the current and projected avoided cost rates for each year.

Figure 1.6.1 identifies DNCP's current avoided energy and capacity rates, as filed with the Commission in Docket No. E-100, SUB 127. Figure 1.6.2 identifies the Company's proposed avoided energy and capacity rates, as filed with the Commission in Docket No. E-100, SUB 136.

Figure 1.6.1 CURRENT AVOIDED ENERGY AND CAPACITY COST (from E-100 Sub 127)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2013	54.84	41.19	8.41
2014	60.13	45.22	18.27
2015	58.77	44.85	49.22

Figure 1.6.2 PROPOSED AVOIDED ENERGY AND CAPACITY COST (from E-100 Sub 136)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2013	43.35	32.35	8.41
2014	47.47	36.75	31.04
2015	52.24	41.47	48.12

1.7 TOTAL & PROJECTED COSTS

In accordance with Rule R8-67(b)(vi), the Company provides the projected total and incremental costs anticipated to implement REPS Compliance plan for each year of the Planning Period

<u>The Company</u>

The Company's Planning Period incremental costs to comply with the Solar Set-Aside, Swine Set-Aside, Poultry Set-Aside and other General Requirements are presented in Figure 1.7.1 below.

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Figure 1.7.1 COMPANY'S REPS COMPLIANCE COST SUMMARY

Type of REC	2013	2014	2015
Solar			
Target (MWh)	2,881	2,923	5,642
REC Cost ($/MWh)[1]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Swine			
Target (MWh)	2,881	2,923	5,642
REC Cost ($/MWh)[2]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Poultry			
Target (MWh)	5,474	20,370	26,100
REC Cost ($/MWh)[3]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
General RECs			
Target (MWh)	112,200	99,031	204,403
Less Energy Efficiency[4]	21,488	25,059	30,101
Net Target	90,712	73,972	174,302
REC Cost ($/MWh)[5]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Projected Administrative and Research Cost[6,7]	$132,253	$616,970	$30,000
TOTAL PROJECTED COMPLIANCE COST	***$546,115***	***$1,443,347***	***$1,467,387***

Notes: (1) Solar REC costs for 2013-2015 are from contracts listed in Figure 1.3.1. (2) Projected REC costs are based on single, signed contract with **[Begin Confidential]** [redacted] **[End Confidential]**. (3) Projected REC costs are based on signed contracts listed in Figure 1.3.2. (4) Projected EE savings represents a projected system allocation. (5) 2013/2014 projected REC costs are based on market estimates, signed contracts and/or ongoing negotiations. (6) Administrative costs include, but are not limited to: NC-RETs fees, broker fees and miscellaneous expenses. (7) As permitted by NCGS § 62-133.8 (h)(1) and (4), DNCP plans to fund a North Carolina research and development (R&D) project in 2013 and 2014 with a total projected cost of $699,223. This figure represents research project cost prior to receiving any offsetting tax credits.

Town of Windsor

Town of Windsor's projected Planning Period REPS costs are expected to consist of the sum of the costs required to comply with,s Solar Set-Aside, Swine Set-Aside, Poultry Set-Aside and other General Requirements Figure 1.7.2 outlines Town of Windsor's Compliance Cost Summary from 2013 to 2015.

CONFIDENTIAL INFORMATION REDACTED

Figure 1.7.2 TOWN OF WINDSOR'S COMPLIANCE COST SUMMARY

Type of REC	2013	2014	2015
Solar			
Target (MWh)	34	34	71
REC Cost ($/MWh)[1]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Swine			
Target (MWh)	34	34	71
REC Cost ($/MWh)[1]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Poultry			
Target (MWh)	68	280	360
REC Cost ($/MWh)[2]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
General REPs			
Target (MWh)	1,283	1,101	2,528
REC Cost ($/MWh)[3]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
TOTAL PROJECTED COMPLIANCE COST	**$11,211**	**$10,409**	**$20,356**

Notes: (1) Solar and Swine REC costs are based on executed contracts. (2) Reflects cost of out-of-state RECs only. (3) 2013-2015 projected REC costs are based on market estimates, signed contracts and/or ongoing negotiations.

1.8 ANNUAL COST CAPS

In accordance with Rule R8-67(b)(vii), the Company provides the following comparison of projected costs to the annual cost caps contained in N.C.G.S. § 62-133.8(h)(4).

Figure 1.8.1 provides a comparison of the Company's projected costs to the annual cost caps for each year of the Planning Period. Compliance costs are allocated to the Customer Classes based on the percentage of each of the Customer Class Cost Caps to the Total Cost Cap.

Figure 1.8.1 COMPANY'S COMPARISON TO ANNUAL CAPS

Compliance Year 2013	**Residential Customers**	**Commercial Customers**	**Industrial Customers**	**Total Customers**
Actual Year-End Annual Customers (2012)	101,085	17,369	50	118,504
Annual Cost Cap per Customer	$12	$150	$1,000	-
Annual Cost Cap, Total	**$1,213,020**	**$2,605,350**	**$50,000**	**$3,868,370**
Projected Cost of Compliance[1]	***$171,247***	***$367,809***	***$7,059***	***$546,115***

Compliance Year 2014	**Residential Customers**	**Commercial Customers**	**Industrial Customers**	**Total Customers**
Projected Year-End Annual Customers (2013)	106,898	18,511	53	125,462
Annual Cost Cap per Customer	$12	$150	$1,000	-
Annual Cost Cap, Total	**$1,282,776**	**$2,776,650**	**$53,000**	**$4,112,426**
Projected Cost of Compliance[1]	***$450,219***	***$974,527***	***$18,602***	***$1,443,347***

Compliance Year 2015	**Residential Customers[2]**	**Commercial Customers**	**Industrial Customers**	**Total Customers**
Projected Year-End Annual Customers (2014)	108,430	18,719	53	127,202
Annual Cost Cap per Customer	$34	$150	$1,000	-
Annual Cost Cap, Total	**$3,686,620**	**$2,807,850**	**$53,000**	**$6,547,470**
Projected Cost of Compliance[1]	***$826,228***	***$629,282***	***$11,878***	***$1,467,387***

Notes: (1) Projected costs were allocated to the customer classes based on customer percentage of total cost cap.
(2) The residential customer cost cap increases in 2015.

Figure 1.8.2 provides a comparison of Town of Windsor's projected costs to the annual cost caps for each year of the REPS Compliance Plan.

Figure 1.8.2 TOWN OF WINDSOR'S COMPARISON TO ANNUAL CAPS

Compliance Year 2013	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Actual Year-End Annual Customers (2012)	1,387	407	1	1,795
Annual Cost Cap per Customer	$12	$150	$1,000	-
Annual Cost Cap, Total	**$16,644**	**$61,050**	**$1,000**	**$78,694**
Projected Cost of Compliance[1]	***$2,371***	***$8,698***	***$142***	***$11,211***

Compliance Year 2014	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers (2013)	1,400	410	1	1,811
Annual Cost Cap per Customer	$12	$150	$1,000	-
Annual Cost Cap, Total	**$16,800**	**$61,500**	**$1,000**	**$79,300**
Projected Cost of Compliance[1]	***$2,205***	***$8,072***	***$131***	***$10,409***

Compliance Year 2015	Residential Customers[2]	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers (2014)	1,450	415	1	1,866
Annual Cost Cap per Customer	$34	$150	$1,000	-
Annual Cost Cap, Total	**$49,300**	**$62,250**	**$1,000**	**$112,550**
Projected Cost of Compliance[1]	***$8,916***	***$11,259***	***$181***	***$20,356***

Notes: (1) Town of Windsor is to determine the allocation among the different customer classes. (2) The residential customer cost cap increases in 2015.

1.9 REPS RIDER

In accordance with Rule R8-67(b)(viii), the Company provides an estimate of the amount of the REPS rider and the impact on the cost of fuel and fuel-related costs rider necessary to fully recover the projected costs.

Figure 1.9.1 REPS Rider Costs

	2013	2014	2015
Total Projected REPS Compliance Costs	$546,115	$1,443,347	$1,467,387
Costs recovered through the Fuel Rider	$0	$0	$0
Total Incremental Cost	$546,115	$1,443,347	$1,467,387
Annual REPS Rider - Residential	$214,281	$574,811	$584,076
Annual REPS Rider - Commercial	$134,181	$340,057	$350,792
Annual REPS Rider - Industrial	$197,652	$528,480	$532,520
Projected Annual Cost Caps (REPS Rider)	**$3,868,370**	**$4,112,426**	**$6,547,470**

NC IRP 2013 UPDATE

ADDENDUM 2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	MOUNT STORM	MEADOWBROOK (529)	500.00	500.00	STEEL POLE			1
2	SURRY	SUFFOLK (531)	500.00	500.00	STEEL	37.27		1
3	DOOMS	CUNNINGHAM (534)	500.00	500.00	STEEL	32.68		1
4	LOUDOUN	MEADOWBROOK (535)	500.00	500.00	STEEL	55.49	10.02	1
5	MOUNT STORM	502 JUNCTION (536)	500.00	500.00	STEEL POLE			1
6	OX	BRISTERS (539)	500.00	500.00	STEEL	22.89		1
7	FLUVANA PWR STA	CUNNINGHAM (542)	500.00	500.00	STEEL	0.28		1
8	PLEASANT VIEW	DOUBS (543)	500.00	500.00	STEEL	3.00		1
9	CARSON	SUFFOLK (544)	500.00	500.00	STEEL	59.63		1
10		(544)	500.00	500.00	STEEL	1.83		
11	BRISTERS	MORRISVILLE (545)	500.00	500.00	STEEL	7.91		1
12	LEXINGTON	BATH (547)	500.00	500.00	STEEL	34.70		1
13	BATH	VALLEY (548)	500.00	500.00	LATTICE	51.82		1
14	VALLEY	DOOMS (549)	500.00	500.00	STEEL	17.72		1
15	MT. STORM	VALLEY (550)	500.00	500.00	STEEL	64.39		1
16	MT. STORM	DOUBS (551)	500.00	500.00	STEEL	96.40		1
17	BRISTERS	LADYSMITH (552)	500.00	500.00	STEEL	35.41		1
18		(552)	500.00	500.00	STEEL		1.20	
19	CUNNINGHAM	ELMONT (553)	500.00	500.00	STEEL	51.03		1
20	MT STORM	PRUNNYTOWN (554)	500.00	500.00	STEEL	0.07		1
21	DOOMS	LEXINGTON (555)	500.00	500.00	STEEL	39.04		1
22	CLOVER	CARSON (556)	500.00	500.00	STEEL	76.72		1
23	ELMONT	CHICKAHOMINY (557)	500.00	500.00	STEEL	27.73		1
24	LOUDOUN	PLEASANT VIEW (558)	500.00	500.00	STEEL	13.01		1
25	LOUDOUN	CLIFTON (559)	500.00	500.00	STEEL	12.08		1
26	POSSUM POINT	BURCHES-PEPCO (560)	500.00	500.00	H.FRAME	0.19		1
27	CLIFTON	OX (561)	500.00	500.00	STEEL	7.05		1
28	CARSON	SEPTA (562)	500.00	500.00	STEEL	38.47		1
29	CARSON	MIDLOTHIAN (563)	500.00	500.00	STEEL	37.41		1
30	CUNNINGHAM	FLUVANA PWR STA (564)	500.00	500.00	STEEL	0.26		1
31	SUFFOLK	YADKIN (565)	500.00	500.00	STEEL	4.80		1
32		(565)	500.00	500.00	ALUM TOWER	8.66		
33	LEXINGTON	CLOVERDALE-APCO (566)	500.00	500.00	STEEL	7.09		1
34	CHICKAHOMINY	SURRY (567)	500.00	500.00	STEEL	44.44		1
35	POSSUM POINT	LADYSMITH (568)	500.00	500.00	STEEL	47.56		1
36					TOTAL	5,500.23	906.24	441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	LOUDOUN	MORRISVILLE (569)	500.00	500.00	STEEL	22.03	0.33	1
2		(569)	500.00	500.00	STEEL	1.26		
3		(569)	500.00	500.00	STEEL	8.16		
4	CARSON	WAKE (570)	500.00	500.00	STEEL	56.40		1
5	OX	POSSUM POINT (571)	500.00	500.00	H.FRAME	12.86		1
6	NORTH ANNA	MORRISVILLE (573)	500.00	500.00	STEEL	32.91		1
7	ELMONT	LADYSMITH (574)	500.00	500.00	STEEL	26.19		1
8	NORTH ANNA	LADYSMITH (575)	500.00	500.00	STEEL	13.52		1
9		(575)	500.00	500.00	H.FRAME	1.01		
10	MIDLOTHIAN	NORTH ANNA (576)	500.00	500.00	STEEL	41.30		1
11	SEPTA	SURRY (578)	500.00	500.00	STEEL	11.46		1
12	FENTRESS	SEPTA (579)	500.00	500.00	LATTICE	46.86		1
13	MORRISVILLE	MEADOWBROOK (580)	500.00	500.00	STEEL	47.39		1
14								
15	SUBTOTAL-500KV		500.00	500.00		1,258.38	11.55	42
16								
17	PENDER	BULL RUN (200)	230.00	230.00	STEEL	0.63		1
18		(200)	230.00	230.00	H.FRAME	2.87		
19		(200)	230.00	230.00	STEEL POLE	3.99		
20	BRAMBLETON	PLEASANT VIEW (201)	230.00	230.00	STEEL	7.97		1
21	IDYLWOOD	CLARK (202)	230.00	230.00	STEEL	4.03		1
22	PLEASANT VIEW	DICKERSON (203)	230.00	230.00	STEEL POLE	1.03		1
23		(203)	230.00	230.00	STEEL POLE	2.09		
24	GUM SPRINGS	JEFFERSON ST (204)	230.00	230.00	STEEL	6.67		1
25		(204)	230.00	230.00	WOOD POLE	4.12		
26	CHESTERFIELD	LOCKS (205)	230.00	230.00	STEEL	2.81		1
27		(205)	230.00	230.00	STEEL	9.42		
28	BRADDOCK	IDYLWOOD (207)	230.00	230.00	STEEL		4.72	1
29	CHESTERFIELD	SOUTHWEST (208)	230.00	230.00	STEEL	14.25		1
30		(208)	230.00	230.00	STEEL	0.15		
31	WALLER	YORKTOWN (209)	230.00	230.00	WOOD	14.36		1
32		(209)	230.00	230.00	STEEL	4.44		
33	HAYFIELD	VAN DORN (210)	230.00	230.00	STEEL		2.90	1
34	CHESTERFIELD	HOPEWELL (211)	230.00	230.00	STEEL	11.17		1
35	HOPEWELL	SURRY (212)	230.00	230.00	H.FRAME	0.27		1
36					TOTAL	5,500.23	906.24	441

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1		(212)	230.00	230.00	STEEL	42.70		
2	LAKEVIEW	THELMA (213)	230.00	230.00	STEEL	8.62		1
3	SURRY	WINCHESTER (214)	230.00	230.00	STEEL	13.90		1
4		(214)	230.00	230.00	STEEL		23.71	
5	POSSUM POINT	HAYFIELD (215)	230.00	230.00	STEEL	12.44		1
6		(215)	230.00	230.00	STEEL	7.62		
7		(215)	230.00	230.00	STEEL POLE	0.48	0.48	
8	LAKESIDE	ELMONT (216)	230.00	230.00	H.FRAME	5.74		1
9	LAKESIDE	CHESTERFIELD (217)	230.00	230.00	H.FRAME	21.22		1
10		(217)	230.00	230.00	H.FRAME		0.10	
11	EVERETTS	GREENVILLE (CP&L) (218)	230.00	230.00	H.FRAME	20.32		1
12		(218)	230.00	230.00	STEEL	1.33		
13	MIDLOTHIAN	SOUTHWEST (219)	230.00	230.00	STEEL POLE	13.77		1
14		(219)	230.00	230.00	STEEL		7.52	
15	OX	GUM SPRINGS (220)	230.00	230.00	STEEL		3.49	1
16		(220)	230.00	230.00	STEEL		6.09	
17		(220)	230.00	230.00	WOOD POLE		4.53	
18	NORTHWEST	ELMONT (221)	230.00	230.00	STEEL	5.93		1
19	NORTHWEST	SOUTHWEST (222)	230.00	230.00	STEEL	10.25		1
20	SURRY	YADKIN (223)	230.00	230.00	STEEL	44.10		1
21	NORTHERN NECK	LANEXA (224)	230.00	230.00	STEEL	41.27		1
22	LAKEVIEW	THELMA (225)	230.00	230.00	STEEL	8.69		1
23	SURRY	CHURCHLAND (226)	230.00	230.00	STEEL		37.63	1
24		(226)	230.00	230.00	STEEL POLE		0.11	
25	BEAUMEADE	BRAMBLETON (227)	230.00	230.00	STEEL	5.19		1
26		(227)	230.00	230.00	STEEL	0.18		
27		(227)	230.00	230.00	STEEL		7.88	
28	CHESTERFIELD	HOPEWELL (228)	230.00	230.00	STEEL		10.97	1
29	EVERETTS	EDGECOMBE (229)	230.00	230.00	STEEL POLE	0.28		1
30		(229)	230.00	230.00	H.FRAME	42.04		
31		(229)	230.00	230.00	STEEL	2.53		
32	YADKIN	LANDSTOWN (231)	230.00	230.00	STEEL	8.54		1
33	GASTON	THELMA (232)	230.00	230.00	STEEL	0.17		1
34	CHARLOTTSVILLE	DOOMS (233)	230.00	230.00	STEEL POLE		14.04	1
35		(233)	230.00	230.00	STEEL POLE		8.63	
36					TOTAL	5,500.23	906.24	441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WINCHESTER	WHEALTON (234)	230.00	230.00	STEEL	0.22		1
2	FARMVILLE	CLOVER (235)	230.00	230.00	STEEL	4.31		1
3		(235)	230.00	230.00	H.FRAME	47.51		
4		(235)	230.00	230.00	H.FRAME	3.64		
5	SOUTHWEST	PLAZA (236)	230.00	230.00	STEEL POLE	3.30		1
6		(236)	230.00	230.00	STEEL POLE	0.74		
7	POSSUM POINT	BRADDOCK (237)	230.00	230.00	STEEL		13.66	
8		(237)	230.00	230.00	STEEL		7.80	
9		(237)	230.00	230.00	STEEL POLE	0.53		
10	CARSON	CLUBHOUSE (238)	230.00	230.00	STEEL	1.02		1
11		(238)	230.00	230.00	H.FRAME	27.53		
12	LAKEVIEW	HORNERTOWN (239)	230.00	230.00	WOOD	2.32		1
13		(239)	230.00	230.00	STEEL		1.74	
14	HOPEWELL	SURRY (240)	230.00	230.00	STEEL		42.97	1
15	JEFFERSON ST.	HAYFIELD (241)	230.00	230.00	STEEL	4.54		1
16		(241)	230.00	230.00	STEEL	1.68		
17	MIDLOTHIAN	TRABUE TAP PT (242)	230.00	230.00	STEEL		3.09	1
18	OX	VAN DORN (243)	230.00	230.00	STEEL	9.68		1
19		(243)	230.00	230.00	STEEL POLE	2.64		
20	BULL RUN	BURKE (244)	230.00	230.00	STEEL POLE	8.87		1
21	GREEN RUN	GREENWICH (245)	230.00	230.00	CON/STEEL	3.99	1.12	1
22	SUFFOLK	EARLEYS (246)	230.00	230.00	H.FRAME	41.29		1
23		(246)	230.00	230.00	STEEL	3.10		
24		NUCOR (246)	230.00	230.00	STEEL POLE	5.38		
25	SUFFOLK	WINFALL (247)	230.00	230.00	H.FRAME	35.28		1
26	GLEBE	OX (248)	230.00	230.00	STEEL POLE	5.09	8.63	1
27		(248)	230.00	230.00	UG-HPOF	3.10		
28		(248)	230.00	230.00	STEEL POLE	1.29		
29	LOCKS	CARSON (249)	230.00	230.00	H.FRAME	7.07		1
30		(249)	230.00	230.00	STEEL		3.64	
31	ARLINGTON	GLEBE (250)	230.00	230.00	STEEL POLE		2.50	1
32	ARLINGTON	IDYLWOOD (251)	230.00	230.00	CONCRETE	0.06		1
33		(251)	230.00	230.00	STEEL POLE		5.18	
34	AQUIA HARBOR	POSSUM POINT (252)	230.00	230.00	STEEL	0.54	11.31	1
35	VALLEY	HARRISONBURG (253)	230.00	230.00	STEEL	2.56		1
36					TOTAL	5,500.23	906.24	441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1		(253)	230.00	230.00	STEEL	8.02		
2	CLUBHOUSE	LAKEVIEW (254)	230.00	230.00	H. FRAME	17.98		1
3	SOUTH ANNA PWR STA	NORTH ANNA (255)	230.00	230.00	H. FRAME	30.04		1
4		(255)	230.00	230.00	H. FRAME	0.63		
5	FOUR RIVERS	LADYSMITH CT (256)	230.00	230.00	H. FRAME	27.27		1
6	CHURCHLAND	SEWELLS POINT (257)	230.00	230.00	STEEL POLE	5.22		1
7		(257)	230.00	230.00	SUBMARINE	1.59		
8	ARLINGTON	GLEBE (258)	230.00	230.00	STEEL POLE	2.49		1
9	BASIN	CHESTERFIELD (259)	230.00	230.00	STEEL POLE	4.40	0.32	1
10		(259)	230.00	230.00	STEEL	3.86	3.68	
11		(259)	230.00	230.00	STEEL	0.14		
12	GROTTOES	HARRISONBURG (260)	230.00	230.00	H. FRAME	10.63		1
13	NEWPORT NEWS	SHELLBANK (261)	230.00	230.00	STEEL POLE	4.86		1
14	YADKIN	GREENWICH (262)	230.00	230.00	STEEL	10.62		1
15		(262)	230.00	230.00	H. FRAME	0.10		
16		(262)	230.00	230.00	STEEL	2.83		
17	CHUCKATUK	NEWPORT NEWS (263)	230.00	230.00	STEEL		13.03	1
18		(263)	230.00	230.00	STEEL		1.81	
19		(263)	230.00	230.00	H. FRAME		0.61	
20	HUNTER	RESTON (264)	230.00	230.00	STEEL	2.67		1
21	CLIFTON	SULLY (265)	230.00	230.00	STEEL		2.68	1
22		(265)	230.00	230.00	STEEL		4.87	
23		(265)	230.00	230.00	STEEL POLE		5.25	
24		(265)	230.00	230.00	STEEL POLE		1.16	
25	CLIFTON	GLEN CARLYN (266)	230.00	230.00	STEEL	7.01		1
26		(266)	230.00	230.00	STEEL POLE	5.15		
27		(266)	230.00	230.00	STEEL POLE	12.44		
28	CHURCHLAND	YADKIN (267)	230.00	230.00	STEEL	9.01	2.29	1
29		(267)	230.00	230.00	STEEL POLE		0.11	
30	COGENTRIX	HOPEWELL (268)	230.00	230.00	STEEL	1.00		1
31	SHAWBORO	FENTRESS (269)	230.00	230.00	STEEL	4.33		1
32		(269)	230.00	230.00	H. FRAME	21.00		
33	BURKE	RAVENSWORTH (270)	230.00	230.00	STEEL	2.98		1
34		(270)	230.00	230.00	U.G.=HPOF	2.18		
35	FENTRESS	LANDSTOWN (271)	230.00	230.00	STEEL	8.80		1
36					TOTAL	5,500.23	906.24	441

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1		(271)	230.00	230.00	CONCRETE	0.17		
2	DOOMS	GROTTOES (272)	230.00	230.00	STEEL	11.53		1
3	GLEN CARLYN	ARLINGTON (273)	230.00	230.00	STEEL		2.44	1
4	BEAUMEADE	PLEASANT VIEW (274)	230.00	230.00	STEEL		0.16	1
5		(274)	230.00	230.00	STEEL POLE		0.18	
6		(274)	230.00	230.00	STEEL		5.06	
7	GLEBE	CRYSTAL (275)	230.00	230.00	U.G.=HPOF	1.23		1
8	GLEBE	CRYSTAL (276)	230.00	230.00	U.G.=HPOF	1.20		1
9	GLEN CARLYN	CLARENDON (277)	230.00	230.00	U.G.=HPOF	1.95		1
10	GLEN CARLYN	CLARENDON (278)	230.00	230.00	U.G.=HPOF	1.95		1
11	THRASHER	REEVES AVENUE (279)	230.00	230.00	STEEL POLE	6.53		1
12	MARSH RUN CT	REMINGTON (280)	230.00	230.00	STEEL		1.24	1
13	BRADDOCK	RAVENSWORTH (281)	230.00	230.00	STEEL		2.06	1
14	SPRUANCE	MIDLOTHIAN (282)	230.00	230.00	STEEL	18.47		1
15		(282)	230.00	230.00	STEEL POLE		3.12	
16	ELMONT	NORTHEAST (283)	230.00	230.00	STEEL	5.22		1
17		(283)	230.00	230.00	H. FRAME	7.97		
18	BASIN	NORTHEAST (284)	230.00	230.00	STEEL	6.27		1
19		(284)	230.00	230.00	H. FRAME	2.26		
20	WALLER	YORKTOWN (285)	230.00	230.00	STEEL POLE	13.53		
21		(285)	230.00	230.00	STEEL	6.43		
22	DARBYTOWN	WHITE OAK (286)	230.00	230.00	STEEL	10.43		1
23		(286)	230.00	230.00	STEEL POLE	3.51		
24	CHESTERFIELD	CHICKAHOMINY (287)	230.00	230.00	H. FRAME		13.95	1
25		(287)	230.00	230.00	STEEL		0.63	
26	PENINSULA	YORKTOWN (288)	230.00	230.00	WOOD POLE		3.21	1
27		(288)	230.00	230.00	STEEL		8.00	
28	SUFFOLK	CHUCKATUCK (289)	230.00	230.00	H. FRAME	0.13		1
29		(289)	230.00	230.00	STEEL	9.85	4.31	
30		(289)	230.00	230.00	3-POLE	0.33		
31	SURRY	CHUCKATUCK (290)	230.00	230.00	STEEL		23.36	1
32		(290)	230.00	230.00	CONCRETE		0.07	
33	DOOMS	CHARLOTTSVILLE (291)	230.00	230.00	STEEL POLE		22.52	1
34	WHEALTON	YORKTOWN (292)	230.00	230.00	STEEL	9.72		1
35		(292)	230.00	230.00	H. FRAME	4.58		
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1	VALLEY	DOOMS (293)	230.00	230.00	H. FRAME	17.73		1
2		(293)	230.00	230.00	STEEL		14.87	
3		(293)	230.00	230.00	STEEL POLE		1.37	
4	ANNANDALE	BRADDOCK (294)	230.00	230.00	U.G.=HPOF	3.58		1
5	LOUDOUN	BULL RUN (295)	230.00	230.00	STEEL		8.67	1
6	HALIFAX	PERSON-CP&L (296)	230.00	230.00	H. FRAME	20.41		1
7	ANNANDALE	BRADDOCK (297)	230.00	230.00	U.G.=HPOF	3.56		1
8	BREMO	FARMVILLE (298)	230.00	230.00	H. FRAME	15.48		1
9		(298)	230.00	230.00	H.FRAME	12.79		
10	REMINGTON CT	MARSH RUN CT (299)	230.00	230.00	STEEL	1.15		1
11		(299)	230.00	230.00	STEEL POLE	0.56		
12	OCCOQUAN	POSSUM POINT (2001)	230.00	230.00	WOOD POLE	0.17		1
13		(2001)	230.00	230.00	STEEL		4.44	
14		(2001)	230.00	230.00	STEEL		8.00	
15	CARSON	POE (2002)	230.00	230.00	WD 3 POLE	0.18		1
16		(2002)	230.00	230.00	STEEL	1.16	4.57	
17		(2002)	230.00	230.00	H.FRAME	6.78		
18	CHESTERFIELD	POE (2003)	230.00	230.00	WOOD POLE	0.19		1
19		(2003)	230.00	230.00	STEEL	7.00		
20		(2003)	230.00	230.00	STEEL		3.18	
21		(2003)	230.00	230.00	STEEL		9.02	
22	PENINSULA	SHELLBANK (2004)	230.00	230.00	STEEL	0.37		1
23		(2004)	230.00	230.00	STEEL POLE	5.92		
24	CLARK	HUNTER (2005)	230.00	230.00	STEEL	2.57		1
25	CHURCHLAND	LAKE KINGMAN (2006)	230.00	230.00	CON/STEEL	1.47		1
26	THALIA	LYNNHAVEN (2007)	230.00	230.00	CON/STEEL	3.37		1
27	LOUDOUN	DULLES (2008)	230.00	230.00	STEEL	4.53		1
28		(2008)	230.00	230.00	STEEL POLE	5.25		
29		(2008)	230.00	230.00	STEEL POLE		3.26	
30		(2008)	230.00	230.00	STEEL POLE	0.21		
31	MIDLOTHIAN	SHORT PUMP (2009)	230.00	230.00	H. FRAME	24.84		1
32	RESTON	TYSONS (2010)	230.00	230.00	STEEL POLE	0.27		1
33		(2010)	230.00	230.00	CONCRETE	4.92		
34		(2010)	230.00	230.00	WOOD POLE	2.64		
35	CLIFTON	CANNON BRANCH (2011)	230.00	230.00	STEEL POLE	7.46		1
36					TOTAL	5,500.23	906.24	441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	ROANOLE VALLEY NUG	EARLEYS (2012)	230.00	230.00	STEEL	3.58		1
2		(2012)	230.00	230.00	H. FRAME		31.91	
3		(2012)	230.00	230.00	H. FRAME		2.10	
4		(2012)	230.00	230.00	H. FRAME		0.11	
5	OCCOQUAN	OX (2013)	230.00	230.00	STEEL POLE		1.45	1
6	EARLEYS	EVERETTS (2014)	230.00	230.00	H. FRAME	32.36	0.26	1
7	RESTON	DULLES (2015)	230.00	230.00	STEEL	1.42		1
8		(2015)	230.00	230.00	STEEL	3.64		
9		(2015)	230.00	230.00	CONC	0.14		
10	LANEXA	HARMONY VILLAGE (2016)	230.00	230.00	STEEL	5.19		1
11		(2016)	230.00	230.00	H. FRAME	25.84		
12	HARRISONBURG	ENDLESS CAVERNS (2017)	230.00	230.00	CONC	19.76		1
13	GREENWICH	E. RIVER NUG (2018)	230.00	230.00	STEEL		11.13	1
14	THALIA	GREENWICH (2019)	230.00	230.00	STEEL POLE	1.17		1
15		(2019)	230.00	230.00	STEEL POLE	1.17		
16	ELIZABETH CITY	WINFALL (2020)	230.00	230.00	H. FRAME	15.35		1
17	ELIZABETH CITY	SHAWBORO (2021)	230.00	230.00	H. FRAME	10.26		1
18	RAVENSWORTH	POSSUM POINT (2022)	230.00	230.00	STEEL	13.68		1
19		(2022)	230.00	230.00	STEEL POLE		0.53	
20		(2022)	230.00	230.00	STEEL POLE	5.68		
21	GLEBE	JEFFERSON STREET (2023)	230.00	230.00	STEEL POLE		0.83	1
22		(2023)	230.00	230.00	UG-HPOF		3.10	
23	CHICKAHOMINY	LANEXA (2024)	230.00	230.00	STEEL	14.26		1
24	GREEN RUN	LYNNHAVEN (2025)	230.00	230.00	STEEL	5.11		1
25		(2025)	230.00	230.00	CONCRETE	1.86		
26	LANDSTOWN	LYNNHAVEN (2026)	230.00	230.00	STEEL		5.88	1
27	MIDLOTHIAN	BREMO (2027)	230.00	230.00	WOOD/ST	35.62		1
28	CHARLOTTSVILLE	BREMO (2028)	230.00	230.00	STEEL	25.53		1
29	CIA	SWINKS MILL (2029)	230.00	230.00	STEEL POLE	3.78		1
30	LOUDOUN	GAINSVILLE (2030)	230.00	230.00	H. FRAME	0.19		1
31		(2030)	230.00	230.00	STEEL		7.56	
32	FOUR RIVERS	ELMONT (2032)	230.00	230.00	H. FRAME	8.93		1
33	CLARK	STERLING PARK (2033)	230.00	230.00	STEEL	2.47		1
34		(2033)	230.00	230.00	STEEL	2.63		
35		(2033)	230.00	230.00	STEEL POLE	1.59		
36					TOTAL	5,500.23	906.24	441

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TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1		(2033)	230.00	230.00	STEEL	3.75		
2	EARLEYS	TROWBRIDGE (2034)	230.00	230.00	H. FRAME	29.57		1
3		(2034)	230.00	230.00	STEEL	5.49		
4	IDYLWOOD	CIA (2035)	230.00	230.00	CONCRETE	6.41		1
5	GLEBE	PENTAGON (2036)	230.00	230.00	U.G. HPFF	2.37		1
6	PENTAGON	RADNOR HEIGHTS (2036)	230.00	230.00	U.G. HPFF	2.67		1
7	GLEBE	PENTAGON (2037)	230.00	230.00	U.G. HPFF	2.37		1
8	GREENWICH	REEVES AVENUE (2038)	230.00	230.00	STEEL POLE	1.83	3.92	1
9	MORRISVILLE	MARSH RUN CT (2039)	230.00	230.00	STEEL	3.92		1
10	MORRISVILLE	MARSH RUN CT (2040)	230.00	230.00	STEEL		3.92	1
11	HOPEWELL	HCF NUG (2041)	230.00	230.00	H.FRAME	0.03		1
12	OCCOQUAN	OGDEN MARTIN (2042)	230.00	230.00	WOOD/ST	2.95	0.36	1
13	DISCOVERY	RESTON (2043)	230.00	230.00	STEEL POLE	1.82		1
14		(2043)	230.00	230.00	STEEL		3.62	
15		(2043)	230.00	230.00	STEEL		1.46	
16	BEAR ISLAND	FOUR RIVERS (2044)	230.00	230.00	WOOD POLE	0.05		1
17	LOUDOUN	BRAMBLETON (2045)	230.00	230.00	ST TOWER	5.08		1
18	HOPEWELL	POLYESTER PWR STA	230.00	230.00	STEEL POLE	0.72		1
19	SURRY	GRAVEL NECK (2047)	230.00	230.00	CONCRETE	0.31		1
20	SURRY	GRAVEL NECK (2048)	230.00	230.00	CONCRETE	0.44		1
21	CHESTERFIELD	ALLIED (2049)	230.00	230.00	STEEL	2.89		1
22		(2049)	230.00	230.00	STEEL POLE	1.67		
23		(2049)	230.00	230.00	H. FRAME	5.35		
24	ALLIED	CHICKAHOMINY (2050)	230.00	230.00	STEEL	5.98		1
25		(2050)	230.00	230.00	H. FRAME	6.58		
26		(2050)	230.00	230.00	STEEL POLE	2.47		
27	CLIFTON	PENDER (2051)	230.00	230.00	STEEL POLE		6.78	1
28		(2051)	230.00	230.00	STEEL	2.88		
29	LEXINGTON	CLIFTON FORGE (2052)	230.00	230.00	STEEL	33.42		1
30	NORTHEAST	DARBYTOWN (2053)	230.00	230.00	STEEL POLE	3.50		1
31	CHARLOTTESVILLE	GORDONSVILLE (2054)	230.00	230.00	H. FRAME	8.41		1
32		(2054)	230.00	230.00	WOOD POLE	15.92		
33	BASIN	BELLEMEADE (2055)	230.00	230.00	STEEL	0.52	0.04	1
34	HORNERTOWN	ROCKY MT. CP&L (2056)	230.00	230.00	H. FRAME	26.25		1
35		(2056)	230.00	230.00	STEEL	2.68		
36					TOTAL	5,500.23	906.24	441

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1		(2056)	230.00	230.00	STEEL		4.16	
2	HORNERTOWN	ROSEMARY (2057)	230.00	230.00	STEEL POLE	0.51		1
3	EDGECOMB	ROCKY MT. CP&L (2058)	230.00	230.00	STEEL	4.81		1
4	CAROLINA	ROCKY VALLEY NUG (2060)	230.00	230.00	STEEL	2.00		1
5		(2060)	230.00	230.00	H. FRAME	2.10		
6	FOUR RIVERS	FOUR RIVERS NUG (2061)	230.00	230.00	STEEL POLE	0.17		1
7	RESTON	DRANESVILLE (2062)	230.00	230.00	STEEL POLE	1.56		1
8		(2062)	230.00	230.00	CONCRETE	1.41		
9	CLIFTON	RAVENSWORTH (2063)	230.00	230.00	STEEL	7.13		1
10	SHAWBORO	KITTY HAWK (2064)	230.00	230.00	ST. H-FRAME	30.08		1
11		(2064)	230.00	230.00	CONC. POLE	2.87		
12		(2064)	230.00	230.00	WOOD POLE	3.96		
13	BASIN	SPRUANCE (2065)	230.00	230.00	STEEL POLE	3.19	0.47	1
14	MIDLOTHIAN	WINTERPOCK (2066)	230.00	230.00	STEEL POLE	2.83	2.74	1
15		(2066)	230.00	230.00	STEEL	2.91		
16		(2066)	230.00	230.00	STEEL		7.72	
17		(2066)	230.00	230.00	STEEL		1.44	
18	FOUR RIVERS	FOUR RIVERS NUG (2067)	230.00	230.00	WOOD POLE	0.06		1
19	CLOVER	HALIFAX (2068)	230.00	230.00	H. FRAME	3.65		1
20		(2068)	230.00	230.00	H. FRAME	12.93		
21		(2068)	230.00	230.00	CON. H.	0.21		
22	YADKIN	ELIZABETH RIVER (2070)	230.00	230.00	STEEL POLE	2.56	0.72	1
23	ELIZABETH RIVER	E. RIVER PWR STA (2071)	230.00	230.00	STEEL POLE	0.08		1
24	LYNNHAVEN	VIRGINIA BEACH (2072)	230.00	230.00	CONCRETE	4.36		1
25	SHAWBORO	KITTY HAWK (2073)	230.00	230.00	ST. H-FRAME		30.26	1
26		(2073)	230.00	230.00	CONC. POLE		2.87	
27		(2073)	230.00	230.00	WD H-FRAME	1.63		
28		(2073)	230.00	230.00	WOOD POLE	4.01		
29		AYDLETT	230.00	230.00	WD H-FRAME	1.63		
30	GORDONSVILLE	SOUTH ANNA (2074)	230.00	230.00	H. FRAME	0.63		1
31		(2074)	230.00	230.00	H. FRAME	0.19		
32		(2074)	230.00	230.00	STEEL POLE	0.21		
33	ELMONT	OLD CHURCH (2075)	230.00	230.00	H. FRAME	32.08		1
34	BIRCHWOOD	NORTHERN NECK (2076)	230.00	230.00	H. FRAME	41.19		1
35		(2076)	230.00	230.00	H. FRAME	3.09		
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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	REMINGTON	REMINGTON CT (2077)	230.00	230.00	ST. POLE	0.54		1
2	POSSUM POINT 500	POSSUM POINT 230 (2078)	230.00	230.00	H.FRAME	0.81		1
3	BEAUMEADE	DRANESVILLE (2079)	230.00	230.00	STEEL POLE	1.51	0.70	1
4		(2079)	230.00	230.00	STEEL	2.12		
5		(2079)	230.00	230.00	CONC POLE	0.04		
6		(2079)	230.00	230.00	STEEL		3.67	
7		(2079)	230.00	230.00	STEEL POLE		1.70	
8	BEAUMEADE	STERLING PARK (2081)	230.00	230.00	STEEL	0.72		1
9		(2081)	230.00	230.00	STEEL		2.24	
10		(2081)	230.00	230.00	CONC POLE		0.03	
11	SEWELLS POINT	NAVY NORTH (2082)	230.00	230.00	U.G. HPFF	2.02		1
12	BIRCHWOOD	FREDERCKSBURG (2083)	230.00	230.00	H. FRAME	12.18		1
13		(2083)	230.00	230.00	H. FRAME		3.05	
14	LEXINGTON	LOWMOOR (2084)	230.00	230.00	STEEL	37.37		1
15	LANDSTOWN	WEST LANDING (2085)	230.00	230.00	STEEL POLE	7.90		1
16	REMINGTON CT	WARRENTON (2086)	230.00	230.00	CONC. POLE	11.20		1
17		(2086)	230.00	230.00	STEEL POLE		0.61	
18	FENTRESS	SHAWBORO (2087)	230.00	230.00	STEEL		4.33	1
19		(2087)	230.00	230.00	STEEL POLE	21.04		
20	GORDONSVILLE	LOUISA CT (2088)	230.00	230.00	H. FRAME	0.58		1
21		(2088)	230.00	230.00	STEEL POLE		0.21	
22	LADYSMITH	LADYSMITH CT (2089)	230.00	230.00	STEEL	3.94		1
23	LADYSMITH CT	FREDERICKSBURG (2090)	230.00	230.00	STEEL		5.20	1
24		(2090)	230.00	230.00	H. FRAME	12.09		
25	WHITE OAK	CHICKAHOMINY (2091)	230.00	230.00	STEEL	3.62		1
26		(2091)	230.00	230.00	STEEL POLE	3.51		
27	SEWELLS POINT	NAVY NORTH (2093)	230.00	230.00	U.G. HPFF	2.01		1
28	BRAMBLETON	LOUDOUN (2094)	230.00	230.00	ST TOWER		5.09	1
29	BEAUMEADE	GREENWAY (2095)	230.00	230.00	STEEL		0.57	1
30		(2095)	230.00	230.00	STEEL POLE	10.48		
31	CLARENDON	BALLSTON (2096)	230.00	230.00	U.G. XLPE	0.42		1
32	OX	IDYLWOOD (2097)	230.00	230.00	STEEL	7.83		1
33		(2097)	230.00	230.00	STEEL	4.47		
34		(2097)	230.00	230.00	STEEL	0.15		
35	PLEASANT VIEW	HAMILTON (2098)	230.00	230.00	STEEL POLE	8.92	1.02	1
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		(2098)	230.00	230.00	U.G. XLPE	2.16		
2	CHURCHLAND	SEWELLS POINT (2099)	230.00	230.00	STEEL POLE		5.25	1
3		(2099)	230.00	230.00	SUBMARINE	1.58		
4	GAINESVILLE	BRISTERS (2101)	230.00	230.00	STEEL		14.48	1
5		(2101)	230.00	230.00	STEEL		1.90	
6	CHICKAHOMINY	WALLER (2102)	230.00	230.00	H. FRAME	0.41		1
7		(2102)	230.00	230.00	STEEL POLE	4.82		
8		(2102)	230.00	230.00	STEEL	9.79	13.68	
9	SHORT PUMP	ELMONT (2103)	230.00	230.00	H. FRAME	9.66		1
10	FREDERICKSBURG	AQUIA HARBOR (2104)	230.00	230.00	H. FRAME	12.63		1
11		(2104)	230.00	230.00	WOOD	0.02		
12	THRASHER	YADKIN (2105)	230.00	230.00	H. FRAME	2.80		1
13		(2105)	230.00	230.00		4.94		
14	BREMO	BEAR GARDEN (2106)	230.00	230.00	STEEL POLE	1.39		1
15	SULLY	DISCOVERY (2107)	230.00	230.00	STEEL POLE	1.16		1
16		(2107)	230.00	230.00	STEEL POLE	1.64		
17	SWINKS MILL	TYSONS (2108)	230.00	230.00	STEEL POLE	2.80		1
18	HARRISONBURG	VALLEY (2109)	230.00	230.00	STEEL		10.23	1
19		(2109)	230.00	230.00	STEEL POLE	0.26	0.09	
20	SUFFOLK	THRASHER (2110)	230.00	230.00	STEEL	7.90	4.94	1
21		(2110)	230.00	230.00	STEEL	8.88		
22	BREMO	BEAR GARDEN (2111)	230.00	230.00	STEEL POLE		1.34	1
23	LANEXA	WALLER (2113)	230.00	230.00	WOOD	14.48		1
24	REMINGTON CT	GAINESVILLE (2114)	230.00	230.00	STEEL		24.56	1
25	GLEN CARLYN	ARLINGTON (2115)	230.00	230.00	STEEL POLE	2.46		1
26	BEAUMEADE	NIVO (2116)	230.00	230.00	U.G. XLPE	0.68		1
27	LANDSTOWN	VA BEACH (2118)	230.00	230.00	ST H-FRAME		10.81	1
28	AQUIA HARBOR	GARRISONVILLE (2119)	230.00	230.00	U.G. XLPE	5.80		1
29	AQUIA HARBOR	GARRISONVILLE (2120)	230.00	230.00	U.G. XLPE	5.80		1
30	HAYES	GAINES POINT (2122)	230.00	230.00	STEEL POLE	3.95		1
31	GAINES POINT	YORKTOWN (2122)	230.00	230.00	HPFF	3.90		
32	HOPEWELL	PRINCE GEORGE (2124)	230.00	230.00	STEEL POLE	2.47		1
33	FENTRESS	THRASHER (2128)	230.00	230.00	STEEL POLE	5.90		1
34	CHICKAHOMINY	LANEXA (2129)	230.00	230.00	H FRAME	14.13		1
35	BEAUMEADE	NIVO (2130)	230.00	230.00	U.G. XLPE	0.72		1
36					TOTAL	5,500.23	906.24	441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	CAROLINA	LAKEVIEW (2141)	230.00	230.00	STEEL	1.27		1
2		(2141)	230.00	230.00	STEEL	0.10		
3								
4	SUBTOTAL - 230		230.00	230.00		2,013.45	668.98	215
5								
6	BREMO	SCOTTSVILLE APCO (8)	138.00	138.00	STEEL	7.30		1
7	ALTAVISTA	NEW LONDON (13)	138.00	138.00	H FRAME			1
8	FUDGE HOLLOW	APCO INTERCONNECT (14)	138.00	138.00	STEEL	14.94		1
9	ALTAVISTA	LEESVILLE (104)	138.00	138.00	STEEL			1
10	EASTMILL	WESTVACO (109)	138.00	138.00	STEEL POLE		0.89	1
11	LOWMOOR	FUDGE HOLLOW (112)	138.00	138.00	STEEL	4.64	0.65	1
12		(112)	138.00	138.00	STEEL POLE	2.14		
13	CLIFTON FORGE	LOWMOOR (133)	138.00	138.00	STEEL	5.05		1
14	EDINBURG	STRASBURG PT. ED. (152)	138.00	135.00	WOOD POLE	16.54		1
15	WESTVACO	FUDGE HOLLOW (155)	138.00	138.00	STEEL POLE	0.46		1
16		(155)	138.00	138.00	WOOD POLE		1.39	
17	LOWMOOR	EASTMILL (161)	138.00	138.00	WOOD POLE	6.41		1
18		(161)	138.00	138.00	STEEL POLE		3.43	
19								
20	SUBTOTAL - 138KV		138.00			57.48	6.36	10
21								
22	VARIOUS	VARIOUS	115.00		H. FRAME			
23			115.00		WOOD POLES	2,068.83	219.35	158
24			115.00		STEEL			
25								
26	SUBTOTAL - 115KV		115.00			2,068.83	219.35	158
27								
28	VARIOUS	VARIOUS	69.00	69.00	H. FRAME	78.85		6
29			69.00	69.00	WOOD POLES			
30			69.00	69.00	UG CABLE	23.24		10
31								
32	SUBTOTAL - 69KV		69.00	69.00		102.09		16
33								
34								
35								
36					TOTAL	5,500.23	906.24	441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACSS 1113								1
ACAR 2500								2
AAAC 2049.5								3
ACSR 1351								4
ACSS 1113								5
ACAR 2500								6
AAAC 2049.5								7
AAAC 2049.5								8
ACSR 1351.5								9
ACSR 1351.5								10
ACAR 2500								11
ACAR 2500								12
ACAR 2500								13
AAAC 2049.5								14
AAAC 2049.5								15
AAAC 2049.5								16
AAAC 2049.5								17
AAAC 2049.5								18
AAAC 2049.5								19
ACSR 2032.1								20
AAAC 2049.5								21
ACSR 1351.5								22
AAAC 2049.5								23
AAAC 2049.5								24
ACAR 2500								25
ACAR 1534								26
ACAR 2500								27
ACAR 2500								28
ACAR 2500								29
AAAC 2049.5								30
ACAR 2500								31
ACAR 2500								32
AAAC 2049.5								33
ACAR 2500								34
ACAR 2500								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACSR 1351								1
AAAC 2049.5								2
ACAR 2500								3
ACAR 2500								4
ACAR 1534								5
ACAR 2500								6
AAAC 2049.5								7
ACAR 2500								8
SDC 2500								9
ACAR 2500								10
ACAR 2500								11
ACAR 2500								12
ACAR 2500								13
	141,349,176	627,011,675	768,360,851	5,148,145	2,057,777	20,477	7,226,399	14
	141,349,176	627,011,675	768,360,851	5,148,145	2,057,777	20,477	7,226,399	15
								16
ACSR 1033.5								17
ACAR 2500								18
ACAR 2500								19
ACSS/TW/HT								20
ACAR 1192.5								21
ACSS/TW 768.2								22
ALUM 1177								23
ACAR 1033.5								24
ACAR 1109								25
ACAR 1109								26
ACSR 1033.5								27
ACAR 2500								28
ACSR 1033.5								29
ACAR 2500								30
ACSR1033.5								31
ACAR 721								32
ACAR 1109								33
ACAR 1109								34
ACAR 2500								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACAR 721								1
ACSR 1033.5								2
ACAR 1534								3
ACAR 721								4
ACAR 721								5
ACAR 2500								6
ACSR 636								7
ACAR 2500								8
ACSR 795								9
ACAR 1534								10
ACAR 1109								11
ACAR 1109								12
ACAR 721								13
ACAR 721								14
ACSR 1033.5								15
ACSS 1033.5								16
ACAR 1109								17
ACAR 721								18
ACSR 1033.5								19
ACAR 721								20
ACAR 1109								21
ACSR 1033.5								22
ACAR 721								23
ACAR 2500								24
SSAC 1192.5								25
ACSR 1590								26
ACSR 1033.5								27
ACAR 1109								28
ACAR 1534								29
ACSR 1033.5								30
ACSR 1033.5								31
AAAC 1177								32
ACSR 795								33
ACAR 545.6								34
ACSR 636								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
ACAR 1534								1
ACSR 545.6								2
ACSR 545.6								3
ACSR 636								4
ACAR 2500								5
ACAR 721								6
ACSR 1033.5								7
SSAC 1033.5								8
ACAR 721								9
ACAR 721								10
ACAR 721								11
ACSR 1033.5								12
ACSR 1033.5								13
ACAR 721								14
ACAR 1033.5								15
ACSR 636								16
ACAR 721								17
ACSR 1033.5								18
ACAR 1109								19
ACAR 1534								20
SSAC 1590								21
ACAR 545								22
ACAR 545								23
ACSR 636								24
ACAR 1109								25
ACAR 2500								26
CU 2500								27
ACSR 636								28
ACSR 795								29
ACSR 795								30
ACAR 2500								31
ACSS 1192.5								32
ACSS 1192.5								33
ACAR 721								34
ACAR 721								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACSR 636								1
ACSR 795								2
ACSR 477								3
ACSR 1590								4
ACSR 795								5
ACAR 721								6
COPPER 1250								7
ACAR 2500								8
ACAR 2500								9
ACSR 1033								10
ACAR 1109								11
ACAR 1109								12
ACAR 1109								13
ACSR 1033								14
ACSR 1033								15
ACAR 721								16
ACAR 1534								17
AAC 1033.5								18
ACAR 1109								19
ACSR 1192								20
ACSR 1033.5								21
ACSR 1033.5								22
ACSR 1590								23
ACAR 1534								24
ACSR 1033.5								25
AAAC 1600								26
ACAR 2500								27
ACAR 721								28
ACAR 2500								29
ACAR 1109								30
ACAR 545								31
ACAR 545								32
ACAR 1534								33
COPPER 1750								34
ACAR 721								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACAR 2500								1
ACAR 721								2
ACAR 1600								3
SSAC 1192.5								4
ACSR 1590								5
ACSR 1192.50								6
COPPER 1750								7
COPPER 1750								8
COPPER 1750								9
COPPER 1750								10
ACAR 721								11
ACSS 795								12
ACAR 2500								13
ACAR 721								14
ACAR 2500								15
ACAR 721								16
ACAR 721								17
ACAR 721								18
ACAR 721								19
ACAR 721								20
ACAR 721								21
ACAR 721								22
								23
ACSR 1033.5								24
ACSR 1033.5								25
ACAR 721								26
ACAR 721								27
ACAR 2500								28
ACAR 721								29
ACAR 721								30
ACAR 721								31
ACAR 2500								32
ACAR 545.6								33
ACSR 1033.5								34
ACAR 721								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACAR 545.6								1
ACAR 545.60								2
ACAR 545.6								3
COPPER 250								4
ACSR 1033								5
ACAR 545.6								6
COPPER 250								7
ACAR 545.6								8
ACAR 545.6								9
ACAR 545.6								10
ACSR 636								11
ACAR 2500								12
ACAR 721								13
ACSR 636								14
ACAR 721								15
ACAR 721								16
ACAR 721								17
ACAR 2500								18
ACAR 721								19
ACAR 1109								20
ACSR 1033.5								21
ACAR 721								22
ACAR 721								23
ACSR 1192.5								24
ACAR 1534								25
ACAR 2500								26
SSAC 1033.5								27
ACSR 1590								28
ACSR 1590								29
ACSR 1590								30
ACSR 636								31
ACSS 1351								32
ACSS 1033.5								33
ACSS 1033.5								34
ACSR 1590								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

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ACAR 545.6								1
ACAR 545.6								2
ACAR 1534								3
AAC 1590								4
ACAR 2500								5
ACAR 545.6								6
SSAC 1192.5								7
SSAC 1033.5								8
SSAC 1033.5								9
SSAC 1033.5								10
SSAC 1033.5								11
								12
ACAR 1534								13
SSAC 1590								14
ACAR 2500								15
ACAR 1109								16
ACAR 545.6								17
ACSR 1033.5								18
ACAR 721								19
ACAR 2500								20
ACAR 2500								21
CU 2500								22
ACAR 721								23
ACAR 721								24
ACAR 2500								25
ACAR 721								26
SSAC 1033.5								27
ACAR 721								28
ACSS 1033.5								29
ACSS 1033.5								30
ACSR 636								31
ACSR 795								32
SSAC 1033.5								33
SSAC 1033.5								34
SSAC 1033.5								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
SSAC 1192.5								1
ACAR 545								2
ACAR 545								3
SSAC 1033.5								4
COPPER 1750								5
COPPER 2500								6
COPPER 1750								7
ACAR 2500								8
ACAR 545.6								9
SSAC 795								10
ACAR 1534								11
ACAR 1534								12
ACSR 1590								13
SSAC 1033.5								14
SSAC 1192.5								15
ACSR 795								16
ACCR 1033-T13								17
ACAR 1534								18
ACSR 1033.5								19
ACSR 1033.5								20
ACSR 636								21
ACSR 636								22
ACSR 636								23
ACSR 636								24
ACSR 636								25
ACSR 636								26
ACAR 2500								27
ACSR 1033.5								28
ACSR 1033								29
ACAR 721								30
ACAR 254.6								31
ACSR 477								32
ACAR 1534								33
ACSR 1033.5								34
ACSR 1033.5								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

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ACAR 1109								1
ACAR 1534								2
ACAR 1109								3
ACAR 545.6								4
ACAR 1534								5
ACSR 1590								6
SSAC 1192.5								7
SSAC 1033.5								8
ACSR 1272								9
ACAR 545.6								10
ACSR/SD 795								11
ACAR 721								12
ACAR 2500								13
ACSR 636								14
ACSR 636								15
ACSR 636								16
ACAR 721								17
ACSR 1590								18
ACSR 636								19
ACSR 477								20
ACSR 545.6								21
ACSR 1534								22
ACSR 1590								23
ACAR 2500								24
ACAR 545.6								25
ACSR/SD 795								26
ACSR 477								27
ACSR 1033.5								28
ACSR 477								29
ACSR 1590								30
ACSR 477								31
ACSR 477								32
ACSR 636								33
ACAR 545.6								34
ACAR 1534								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACSR 636								1
ACSR 636								2
ACSR 2-636								3
ACSR 1192.5								4
SSAC 1033.5								5
SSAC 1192.5								6
SSAC 1192.5								7
ACSR 1192.5								8
SSAC 1192.5								9
SSAC 1033.5								10
CU 2500								11
ACAR 545.6								12
ACAR 1534								13
ACSR 477								14
ACSR 636								15
ACAR 1109								16
ACAR 1109								17
ACAR 545.6								18
ACSR 636								19
ACSR 477								20
ACSR 477								21
ACSR 636								22
ACSR 795								23
ACSR 795								24
ACAR 721								25
ACSR 636								26
CU 2500								27
ACSS/TW 1233.6								28
ACSR 636								29
ACSR 636								30
CU 1500								31
ACSS 1033.5								32
ACSR 795								33
ACSR 636								34
ACSR 636								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

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TRANSMISSION LINE STATISTICS (Continued)

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
CU 3500								1
ACAR 721								2
COPPER 1250								3
ACSR 636								4
ACSR 636								5
ACSR 636								6
ACAR 721								7
ACAR 721								8
ACAR 1109								9
ACAR 721								10
ACAR 1109								11
ACSR 1033.5								12
ACSR 636								13
ACSR 636								14
ACAR 1534								15
ACSR 1590								16
ACSS 1033.5								17
ACAR 721								18
ACSR 636								19
ACSR 636								20
ACAR 2500								21
ACSR 636								22
ACSR 1033.5								23
ACSR 636								24
ACSS 1192.5								25
CU 3500								26
ACSR/AW 1351								27
CU 3500								28
CU 3500								29
ACSR 1033.5								30
CU 2500								31
ACSR 636								32
ACAR 721								33
ACSR 1033.5								34
CU 3500								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACSR 795								1
ACSR 1033.5								2
	174,594,545	947,304,355	1,121,898,900	10,874,251	4,346,572	43,253	15,264,076	3
	174,594,545	947,304,355	1,121,898,900	10,874,251	4,346,572	43,253	15,264,076	4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
	12,949,554	40,074,330	53,023,884	258,800	103,445	1,029	363,274	19
	12,949,554	40,074,330	53,023,884	258,800	103,445	1,029	363,274	20
								21
VARIOUS								22
								23
								24
	98,536,873	380,409,040	478,945,913	9,276,009	3,707,734	36,896	13,020,639	25
	98,536,873	380,409,040	478,945,913	9,276,009	3,707,734	36,896	13,020,639	26
								27
								28
								29
								30
	1,679,623	11,508,612	13,188,235	413,861	165,425	1,646	580,932	31
	1,679,623	11,508,612	13,188,235	413,861	165,425	1,646	580,932	32
								33
								34
								35
	429,109,771	2,006,308,012	2,435,417,783	25,971,066	10,380,953	103,301	36,455,320	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Line 57	Mt Airy Tap	7.80	ST POLE	11.00	1	1
2	Line 64	Chowan River Crossing	5.28	ST H-FRAME	8.00	1	1
3	Farmville	Pamplin (84)	17.61	ST H-FRAME	8.00	1	1
4	Bremo	Transco (91)	12.25	ST H-FRAME	9.00	1	1
5	Line 98	Nutbush Tap	5.42	ST POLE	11.00	1	1
6	Bull Run	Harrison DP (134, 163)	0.60	ST POLE	25.00	2	2
7	Dooms (146, 160)	Dupont-Waynesboro	4.90	ST POLE	8.00	2	2
8	Chuckatuck	Newport News (263)	2.41	VARIES	9.00	2	2
9	Pentagon	Radnor Heights (2036)	2.67	Underground		1	2
10	Remington CT	Gainesville (2114)	20.93	ST TOWER	6.00	2	2
11	Landstown	Va Beach (2118)	10.81	ST H-FRAME	8.00	2	2
12	Hayes	Gaines Point (2122)	3.95	ST POLE	7.00	1	1
13	Gaines Point	Yorktown (2122)	3.90	Submarine		1	2
14	Hopewell	Prince George (2124)	2.47	ST POLE	9.00	1	1
15	Mt Storm	Doubs (551)	12.16	ST TOWER	4.00	1	1
16							
17							
18							
19							
20							
21							
22							
23							
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25							
26							
27							
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38							
39							
40							
41							
42							
43							
44	TOTAL		113.16		123.00	20	22

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
336.4	ACSR	VERT 10'	115		2,650,562	596,956	117,359	3,364,877	1
1231	ACSS	HORIZ 17'	115		15,640,810	2,198,032	1,079,575	18,918,417	2
1033.5	ACSR	HORIZ 17'	115		8,327,396	4,066,886	756,744	13,151,026	3
636	ACSR	HORIZ 17'	115		12,482,154	7,503,255	976,990	20,962,399	4
336.4	ACSR	VERT 10'	115		1,949,229	469,283	207,506	2,626,018	5
1590	ACSS	VERT 10'	115		650,700	543,587	105,548	1,299,835	6
636	ACSR	VERT 20.5'	115	1,780,690	10,631,057	3,463,892	499,540	16,375,179	7
1033.5	ACSR	VERT 20.5	230			1,040,190	72,000	1,112,190	8
2500	CU	SPIRAL 8"	230			16,659,498		16,659,498	9
636	ACSR	DELTA 17'HOR	230		1,265,661	1,556,304	79,413	2,901,378	10
1351	ACSR/AW	HORIZ 17'	230		20,889,130	6,644,804	2,097,064	29,630,998	11
1033.5	ACSR	VERT 18.5	230	9,642	7,159,156	1,730,123		8,898,921	12
2500	CU	Varies	230			61,670,099		61,670,099	13
636	ACSR	DELTA 20.5'	230		6,402,147	1,663,330	513,625	8,579,102	14
1351	ACSR	DELTA 29'HOR	500		10,905,849	10,885,161	3,449,053	25,240,063	15
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				1,790,332	98,953,851	120,691,400	9,954,417	231,390,000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ACCA	D	115.00	34.50	
2	ACCA	D	115.00	13.20	
3	AHOSKIE	D	115.00	34.50	
4	AIRLINE	D	34.50	4.16	
5	ALEXANDERS CORNER	D	34.50	13.20	
6	ALEXANDERS CORNER	D	115.00	13.20	
7	ALEXANDRIA PLANT	D	34.50	4.16	
8	ALLEGHANY	D	46.00	12.50	
9	ALTAVISTA	T	138.00	115.00	12.50
10	ALTAVISTA	T	138.00	69.00	13.20
11	ANNANDALE	D	34.50	12.50	
12	ANNANDALE	D	230.00	34.50	
13	AQUIA	D	230.00	34.50	
14	ARLINGTON	D	34.50	13.20	
15	ARLINGTON	D	230.00	34.50	
16	ARNOLDS CORNER	D	230.00	34.50	
17	ASHBURN	D	230.00	34.50	
18	ASHTON	D	13.20	4.16	
19	ATLANTIC	D	34.50	13.20	
20	AYDLETT	D	230.00	34.50	13.20
21	BAILEYS X-ROADS	D	34.50	12.50	
22	BAINS STORE	D	115.00	34.50	13.20
23	BALLSTON	T	230.00	69.00	
24	BALLSTON	D	230.00	34.50	
25	BANISTER	D	138.00	34.50	
26	BARRACKS ROAD	D	230.00	34.50	
27	BASIN	D	115.00	13.20	
28	BASIN	T	230.00	115.00	13.20
29	BASIN	D	230.00	34.50	
30	BATTLEBORO	D	115.00	34.50	2.40
31	BATTLEFIELD	D	34.50	13.20	
32	BAYSIDE	D	34.50	13.20	
33	BAYSIDE	D	115.00	34.50	13.20
34	BAYSIDE	D	115.00	13.20	
35	BEARSKIN	T	138.00	69.00	13.20
36	BEAUMEADE	D	230.00	34.50	
37	BECO	D	230.00	34.50	
38	BELLE HAVEN	D	34.50	12.50	
39	BELLWOOD	D	115.00	13.20	
40	BELVOIR	D	230.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BENNS CHURCH	D	34.50	12.50	
2	BERKLEY	D	115.00	11.00	
3	BETHEL CAROLINA	D	115.00	12.50	
4	BEVERLY HILLS	D	34.50	4.16	
5	BLOXOMS CORNER	D	115.00	23.00	
6	BOLLINGBROOK	D	34.50	4.16	
7	BOWERS HILL	D	230.00	34.50	
8	BOYKINS	D	115.00	34.50	
9	BRADDOCK	D	34.50	12.50	
10	BRADDOCK	D	230.00	34.50	
11	BRAMBLETON	D	230.00	34.50	
12	BREMO	D	115.00	34.50	13.20
13	BREMO	T	138.00	115.00	13.20
14	BREMO	T	230.00	115.00	13.20
15	BRIARFIELD	D	23.00	6.00	
16	BRISTERS	T	500.00	230.00	
17	BRISTERS	T	230.00	115.00	13.20
18	BRODNAX	D	115.00	12.50	
19	BRUNSWICK	T	115.00	69.00	13.20
20	BUCHANAN	D	46.00	12.50	
21	BUCKINGHAM	D	34.50	12.50	
22	BUCKINGHAM	D	230.00	34.50	
23	BUCKROE	D	23.00	6.00	
24	BUENA VISTA	D	115.00	12.50	
25	BULL RUN	T	230.00	115.00	13.20
26	BURKE	D	230.00	34.50	
27	BURTON	D	115.00	34.50	13.20
28	CALLAO	D	34.50	12.50	
29	CAMPOSTELLO	D	11.00	4.16	
30	CANNON BRANCH	D	115.00	34.50	
31	CANNON BRANCH	T	230.00	115.00	13.20
32	CAROLINA	D	115.00	13.20	
33	CAROLINA	T	230.00	115.00	13.20
34	CARROLL	D	34.50	13.20	
35	CARSON	T	500.00	230.00	34.50
36	CARSON	T	500.00	230.00	
37	CARTERSVILLE	D	115.00	34.50	
38	CARVER	D	115.00	34.50	
39	CARVER	D	115.00	13.20	
40	CASHIE	D	230.00	34.50	

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CASH'S CORNER	T	230.00	115.00	
2	CENTRAL	D	115.00	12.50	
3	CENTRALIA	D	115.00	13.20	
4	CENTREVILLE	D	230.00	34.50	
5	CHANCELLOR	D	115.00	34.50	
6	CHANCELLOR	T	500.00	115.00	
7	CHARLES CITY RD	D	230.00	34.50	
8	CHARLOTTESVILLE	D	34.50	12.50	
9	CHARLOTTESVILLE	D	230.00	34.50	
10	CHASE CITY	D	115.00	12.50	
11	CHATHAM	D	69.00	12.50	
12	CHERRYDALE	D	34.50	12.50	
13	CHESTERBROOK	D	34.50	13.20	
14	CHESTERFIELD 230	T	230.00	115.00	13.20
15	CHICKAHOMINY	T	500.00	230.00	34.50
16	CHICKAHOMINY	D	230.00	13.20	
17	CHOWAN	D	115.00	34.50	
18	CHURCHLAND	D	115.00	13.20	
19	CHURCHLAND	T	230.00	115.00	13.20
20	CHURCHLAND	D	230.00	34.50	
21	CIA	D	230.00	34.50	
22	CITY HALL	D	34.50	11.00	
23	CLARENDON	D	230.00	34.50	
24	CLARENDON	T	230.00	69.00	
25	CLARK	D	230.00	34.50	
26	CLARKSVILLE	D	115.00	13.20	
27	CLIFTON	T	500.00	230.00	
28	CLIFTON FORGE	D	138.00	46.00	13.20
29	CLIFTON FORGE	D	138.00	12.50	
30	CLIFTON FORGE	T	230.00	138.00	13.20
31	CLOVER	T	500.00	230.00	
32	CLUBHOUSE	T	230.00	115.00	13.20
33	COLINGTON	D	115.00	34.50	
34	COLONIAL HEIGHTS	D	13.20	4.16	
35	COLONY	D	115.00	34.50	
36	COLONY	D	115.00	13.20	
37	COLUMBIA	D	34.50	12.50	
38	COLUMBIA FURNACE	D	34.50	23.00	
39	COOKS CORNER	D	34.50	12.50	
40	COPELAND PARK	D	115.00	23.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CORRECTIONAL	D	230.00	34.50	
2	COTTAGE PARK	D	34.50	13.20	
3	COVINGTON	D	46.00	12.50	
4	COVINGTON	D	138.00	46.00	12.50
5	CRADOCK	D	115.00	34.50	
6	CRAIGSVILLE	D	115.00	23.00	
7	CRANES CORNER	D	230.00	34.50	
8	CRESWELL	D	34.50	12.50	
9	CRESWELL	D	115.00	34.50	
10	CREWE	D	115.00	13.20	
11	CRITTENDEN	D	230.00	34.50	
12	CROMWELL ROAD	D	34.50	4.16	
13	CROZET	D	230.00	34.50	
14	CRYSTAL	D	230.00	34.50	
15	CULPEPER	D	115.00	34.50	
16	CULPEPER REA	D	34.50	12.50	
17	CUSHAW	D	12.50	2.40	
18	DAVIS CORNER	D	115.00	34.50	13.20
19	DAVIS CORNER	D	115.00	13.20	
20	DAYTON	D	230.00	34.50	
21	DEEP CREEK	D	115.00	13.20	
22	DELTAVLLE	D	34.50	12.50	
23	DENBIGH	D	230.00	34.50	
24	DIAMOND SPRINGS	D	34.50	13.20	
25	DINWIDDIE	D	34.50	13.20	
26	DISPUTANTA	D	115.00	13.20	
27	DOMINION	D	115.00	34.50	
28	DOOMS 115	D	115.00	23.00	
29	DOOMS 500	T	230.00	115.00	13.20
30	DOOMS 500	T	500.00	230.00	
31	DOZIER	D	34.50	13.20	
32	DOZIER	D	115.00	13.20	
33	DRANESVILLE	D	230.00	34.50	
34	DRY RUN	D	46.00	12.50	
35	DRYBURG	D	115.00	12.50	
36	DULLES	D	230.00	34.50	
37	DUMFRIES	D	230.00	34.50	
38	DUNNSVILLE	D	230.00	34.50	
39	DUPONT	D	115.00	13.20	
40	EAGLE ROCK	D	46.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EARLEYS	D	115.00	34.50	
2	EARLEYS	T	230.00	115.00	13.20
3	EAST END	D	23.00	6.00	
4	EAST OCEAN VIEW	D	34.50	13.20	
5	EDENTON	D	115.00	12.50	
6	EDGEWATER	D	34.50	4.16	
7	EDINBURG	D	115.00	34.50	
8	EDINBURG	T	138.00	115.00	13.20
9	ELEVENTH STREET	D	34.50	4.16	
10	ELIZABETH CITY	D	230.00	34.50	
11	ELKO	D	230.00	34.50	
12	ELM	D	34.50	12.50	
13	ELMONT	T	230.00	115.00	13.20
14	ELMONT	D	230.00	34.50	
15	ELMONT	T	500.00	230.00	
16	EMPORIA	D	115.00	12.50	
17	ENDLESS CAVERNS	D	115.00	34.50	
18	ENDLESS CAVERNS	T	230.00	115.00	13.20
19	ENGLESIDE	D	34.50	12.50	
20	ENON	D	34.50	13.20	
21	ENON	D	230.00	34.50	
22	EVERETTS	T	230.00	115.00	13.20
23	EVERETTS	D	230.00	34.50	
24	FAIRFAX	D	34.50	12.50	
25	FAIRFIELD	D	115.00	23.00	
26	FALLS CHURCH	D	34.50	12.50	
27	FALLS CHURCH	D	230.00	34.50	
28	FARMVILLE	D	115.00	12.50	
29	FARMVILLE	T	230.00	115.00	13.20
30	FARMVILLE	D	230.00	34.50	
31	FENTRESS	D	230.00	34.50	13.20
32	FENTRESS	T	500.00	230.00	
33	FISHERSVILLE	D	115.00	23.00	
34	FLAGGY RUN	D	34.50	13.20	
35	FORT HUNT	D	34.50	12.50	
36	FORT LEE	D	115.00	13.20	
37	FORT MYER	D	34.50	12.50	
38	FORT PICKETT	D	115.00	12.50	
39	FOX HALL	D	34.50	4.16	
40	FRANCONIA	D	230.00	34.50	

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FRANKLIN	D	115.00	13.20	
2	FREDERICKSBURG	D	115.00	34.50	
3	FREDERICKSBURG	D	115.00	13.20	
4	FREDERICKSBURG	T	230.00	115.00	13.20
5	FREDERICKSBURG	D	230.00	34.50	
6	GAINESVILLE	T	230.00	115.00	13.20
7	GAINESVILLE	D	230.00	34.50	
8	GALLOWS ROAD	D	230.00	34.50	
9	GARRISONVILLE	D	230.00	34.50	
10	GARYSVILLE	D	34.50	13.20	
11	GATESVILLE	D	34.50	12.50	
12	GLASGOW	D	115.00	46.00	13.20
13	GLASGOW	D	115.00	12.50	
14	GLEBE	D	230.00	34.50	
15	GLEN CARLYN	D	230.00	34.50	
16	GOLDMINE DP	D	34.50	13.20	
17	GORDONSVILLE	D	115.00	34.50	
18	GORDONSVILLE	T	230.00	115.00	13.20
19	GOSHEN	D	115.00	46.00	4.16
20	GOSHEN	D	115.00	23.00	
21	GOWRIE PARK	D	34.50	4.16	
22	GRAFTON	D	115.00	34.50	
23	GRASSFIELD	D	115.00	34.50	13.20
24	GREAT BRIDGE	D	115.00	34.50	13.20
25	GREEN HILL	D	34.50	4.16	
26	GREEN RUN	D	230.00	34.50	13.20
27	GREENWAY	D	230.00	34.50	
28	GREENWICH	T	230.00	115.00	13.20
29	GREENWICH	D	230.00	34.50	13.20
30	GRETNA	D	69.00	12.50	
31	GROTTOES	D	23.00	13.20	
32	GROTTOES	D	115.00	23.00	
33	GROTTOES	D	115.00	12.50	
34	GROTTOES	T	230.00	115.00	13.20
35	GROVE AVENUE	D	34.50	13.20	
36	GROVELAND	D	34.50	13.20	
37	GUM SPRINGS	D	230.00	34.50	
38	HALIFAX	T	230.00	115.00	13.20
39	HAMILTON	D	230.00	34.50	
40	HAMPTON	D	23.00	6.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

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1	HANOVER	D	115.00	13.20	
2	HANOVER	D	230.00	34.50	
3	HARBOUR VIEW	D	230.00	34.50	
4	HARMONY VILLAGE	D	115.00	34.50	
5	HARMONY VILLAGE	T	230.00	115.00	13.20
6	HARMONY VILLAGE	D	230.00	34.50	
7	HARRISONBURG	D	115.00	34.50	
8	HARRISONBURG	T	230.00	115.00	13.20
9	HARRISONBURG	T	230.00	69.00	13.20
10	HARROWGATE	D	115.00	13.20	
11	HARROWGATE	D	230.00	34.50	
12	HARVELL	D	115.00	13.20	
13	HAYES	D	115.00	34.50	
14	HAYES	T	230.00	115.00	13.20
15	HAYFIELD	D	230.00	34.50	
16	HERNDON PARK	D	230.00	34.50	
17	HERTFORD	D	34.50	13.20	
18	HICKORY	D	115.00	34.50	13.20
19	HICKORY	D	115.00	13.20	
20	HICKORY	T	230.00	115.00	13.20
21	HILLWOOD	D	34.50	13.20	
22	HILTON	D	34.50	6.00	
23	HODGES FERRY	D	115.00	34.50	
24	HODGES FERRY	D	115.00	13.20	
25	HOLLAND	D	115.00	13.20	
26	HOLLIN HALL	D	34.50	13.20	
27	HOLLYMEADE	D	230.00	34.50	
28	HOPEWELL	D	34.50	13.20	
29	HOPEWELL	D	230.00	34.50	13.20
30	HORNERTOWN	D	230.00	34.50	
31	HORNERTOWN	D	115.00	13.20	
32	HORNERTOWN	D	230.00	34.50	
33	HULL ST	D	230.00	34.50	
34	HUNTER	D	230.00	34.50	
35	IDYLWOOD	D	34.50	13.20	
36	IDYLWOOD	D	230.00	34.50	
37	IGLOO	D	34.50	12.50	
38	ILDA	D	34.50	13.20	
39	INDUSTRIAL PARK	D	115.00	34.50	13.20
40	INDUSTRIAL PARK	D	115.00	13.20	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	IRONBRIDGE	D	230.00	34.50	
2	IVOR	D	115.00	13.20	
3	IVY	D	23.00	6.00	
4	JACKSON RIVER	D	46.00	12.50	
5	JARRATT	D	115.00	13.20	
6	JEFFERSON STREET	D	230.00	34.50	
7	JETERSVILLE	D	115.00	34.50	
8	KEENE MILL	D	230.00	34.50	
9	KELFORD	D	115.00	34.50	
10	KENBRIDGE	D	115.00	12.50	
11	KINDERTON	D	115.00	12.50	
12	KING GEORGE	D	34.50	13.20	
13	KINGS FORK	D	115.00	34.50	
14	KINGS FORK	D	115.00	13.20	
15	KINGS FORK	D	230.00	34.50	
16	KINGS MILL	D	115.00	34.50	
17	KINGS MILL	D	230.00	34.50	
18	KITTY HAWK	D	34.50	13.20	
19	KITTY HAWK	D	115.00	34.50	13.20
20	KITTY HAWK	T	230.00	115.00	13.20
21	KITTY HAWK	D	230.00	34.50	13.20
22	LABURNUM	D	34.50	4.16	
23	LADYSMITH	T	500.00	230.00	
24	LAFAYETTE	D	34.50	4.16	
25	LAKE GASTON	D	115.00	34.50	
26	LAKELAND	D	34.50	4.16	
27	LAKERIDGE	D	230.00	34.50	
28	LAKESIDE	D	115.00	13.20	
29	LAKESIDE	T	230.00	115.00	13.20
30	LAKESIDE	D	230.00	34.50	
31	LAKESIDE	D	230.00	13.20	
32	LANCASTER	D	115.00	34.50	
33	LANCASTER	D	115.00	13.20	
34	LANDSTOWN	T	230.00	115.00	13.20
35	LANDSTOWN	D	230.00	34.50	13.20
36	LANEXA	D	115.00	13.20	
37	LANEXA	T	230.00	115.00	13.20
38	LAUREL AVE	D	34.50	4.16	
39	LAWRENCEVILLE	D	115.00	34.50	
40	LAWRENCEVILLE	D	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LEBANON	D	115.00	34.50	
2	LEBANON	D	115.00	13.20	
3	LEE D.P.	D	34.50	13.20	
4	LEESBURG	D	34.50	13.20	
5	LEMON	D	34.50	13.20	
6	LENOX	D	34.50	4.16	
7	LEXINGTON	T	230.00	115.00	13.20
8	LEXINGTON	T	500.00	230.00	
9	LIGHTFOOT	D	230.00	34.50	
10	LILLEY	D	34.50	12.50	
11	LIVINGSTON HEIGHT	D	34.50	13.20	
12	LOCKS	D	115.00	34.50	
13	LOCKS	D	115.00	13.20	
14	LOCKS	T	230.00	115.00	13.20
15	LONDON BRIDGE	D	115.00	34.50	13.20
16	LONG CREEK	D	115.00	34.50	13.20
17	LOUDOUN	T	230.00	115.00	13.20
18	LOUDOUN	T	500.00	230.00	
19	LOUISA	D	230.00	34.50	
20	LOVETTSVILLE	D	138.00	34.50	
21	LOW MOOR	T	230.00	138.00	13.20
22	LYNNHAVEN	D	34.50	13.20	
23	LYNNHAVEN	D	230.00	34.50	13.20
24	MADISON ST	D	13.20	4.16	
25	MAGRUDER	D	115.00	34.50	
26	MAGRUDER	D	115.00	13.20	
27	MANCHESTER	D	115.00	13.20	
28	MANTEO	D	34.50	13.20	
29	MARGARETTSVILLE	D	115.00	13.20	
30	MASSANUTTEN	D	34.50	12.50	
31	MATHEWS	D	34.50	13.20	
32	MCKENNEY	D	34.50	13.20	
33	MCLAUGHLIN	D	115.00	34.50	13.20
34	MCLEAN	D	34.50	13.20	
35	MECHANICSVILLE	D	34.50	13.20	
36	MERCK 5	D	115.00	34.50	
37	MERCURY	D	115.00	23.00	
38	MERRIFIELD	D	34.50	13.20	
39	MERRY POINT	D	34.50	13.20	
40	METCALF	D	115.00	12.50	

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MIDDLEBURG	D	115.00	34.50	
2	MIDDLETON D.P.	D	34.50	13.20	
3	MIDLOTHIAN 34.5	D	230.00	34.50	
4	MIDLOTHIAN 500	T	500.00	230.00	34.50
5	MINE ROAD	D	230.00	34.50	
6	MONTROSS	D	34.50	13.20	
7	MORRISVILLE	T	500.00	230.00	
8	MOUNT EAGLE	D	230.00	34.50	
9	MOUNT LAUREL	D	115.00	12.50	
10	MOUNTAIN ROAD	D	230.00	34.50	
11	MT JACKSON	D	115.00	34.50	
12	MURPHY	D	115.00	34.50	
13	MYRTLE	D	115.00	34.50	
14	NAGS HEAD	D	115.00	34.50	
15	NASH	D	230.00	34.50	13.20
16	NEW MARKET	D	34.50	12.50	
17	NEWPORT NEWS #2	D	23.00	6.00	
18	NEWPORT NEWS #2	D	230.00	23.00	
19	NIVO	D	230.00	34.50	
20	NOKESVILLE	D	230.00	34.50	
21	NORTH ANNA 500/22	T	500.00	230.00	
22	NORTH POLE	D	230.00	34.50	
23	NORTH VA. BEACH	D	34.50	13.20	
24	NORTHEAST	D	115.00	13.20	
25	NORTHEAST	T	230.00	115.00	13.20
26	NORTHEAST	D	230.00	34.50	
27	NORTHERN NECK	D	115.00	34.50	
28	NORTHERN NECK	T	230.00	115.00	13.20
29	NORTHHAMPTON	D	230.00	34.50	
30	NORTHWEST	D	115.00	13.20	
31	NORTHWEST	T	230.00	115.00	13.20
32	NORTHWEST	D	230.00	34.50	
33	NORVIEW	D	34.50	4.16	
34	OAK GROVE	D	230.00	34.50	
35	OAK RIDGE	D	115.00	13.20	
36	OAKWOOD	D	115.00	34.50	13.20
37	OAKWOOD	D	115.00	13.20	
38	OCCOQUAN	D	230.00	34.50	
39	OCEAN VIEW	D	34.50	4.16	
40	OFFICE HALL D.P.	D	34.50	13.20	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OKISKO	D	34.50	12.50	
2	OLD CHURCH	D	230.00	34.50	
3	ORANGE	D	115.00	34.50	
4	ORANGE	D	115.00	12.50	
5	OTTER RIVER	D	115.00	12.50	
6	OX	T	500.00	230.00	
7	PAGAN	D	34.50	13.20	
8	PAMPLIN	D	34.50	23.00	
9	PAMPLIN	D	115.00	34.50	
10	PANTEGO	D	115.00	34.50	
11	PARMELE	D	115.00	12.50	
12	PASQUOTANK	D	230.00	34.50	
13	PEARSONS	D	230.00	34.50	
14	PENDER	D	230.00	34.50	
15	PENDLETON	D	115.00	34.50	13.20
16	PENINSULA	D	34.50	13.20	
17	PENINSULA	D	115.00	34.50	
18	PENINSULA	T	230.00	115.00	13.20
19	PENINSULA	D	230.00	34.50	
20	PENNIMAN	D	230.00	34.50	
21	PENTAGON	T	230.00	69.00	
22	PERTH	D	115.00	34.50	
23	PHOEBUS	D	23.00	6.00	
24	PICKETT STREET	D	34.50	13.20	
25	PINE ST	D	34.50	11.00	
26	PLAZA	D	115.00	13.20	
27	PLAZA	T	230.00	115.00	13.20
28	PLAZA	D	230.00	34.50	
29	PLEASANT VIEW	D	230.00	34.50	
30	PLEASANT VIEW 500	T	500.00	230.00	
31	PLYMOUTH	D	115.00	34.50	
32	POE	D	34.50	13.20	
33	POE	T	230.00	115.00	13.20
34	POE	D	230.00	34.50	
35	POINT HARBOR	D	230.00	34.50	13.20
36	POOLESVILLE	D	230.00	34.50	
37	POPLAR CHAPEL	D	115.00	34.50	
38	PORT NORFOLK	D	34.50	4.16	
39	PORTSMOUTH	T	230.00	115.00	13.20
40	POSSUM POINT 230	T	230.00	115.00	13.20

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SUBSTATIONS

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1	POSSUM POINT 500	T	500.00	230.00	
2	POTOMAC	D	34.50	4.16	
3	POWHATAN	D	230.00	34.50	
4	PRENTIS PARK	D	34.50	4.16	
5	PRINCE GEORGE	T	230.00	115.00	13.20
6	PRINCESS ANNE	D	115.00	34.50	13.20
7	PROVIDENCE FORGE	D	115.00	34.50	
8	PUNGO RIVER	D	34.50	13.20	
9	PURCELLVILLE	D	34.50	13.20	
10	Q ST	D	34.50	13.20	
11	QUANTICO	D	115.00	13.20	
12	RADNOR HEIGHTS	D	230.00	34.50	
13	RADNOR HEIGHTS	D	34.50	13.20	
14	RAVENSWORTH	D	230.00	34.50	
15	REDDFIELD	D	230.00	34.50	
16	REEDY CREEK	D	115.00	34.50	
17	REEVES AVE	D	115.00	34.50	13.20
18	REEVES AVE	T	230.00	115.00	13.20
19	REMINGTON	D	115.00	34.50	
20	REMINGTON	T	230.00	115.00	13.20
21	REMINGTON CT	T	230.00	115.00	13.20
22	RESERVOIR	D	34.50	4.16	
23	RESTON	D	230.00	34.50	
24	RIDERS CREEK	D	115.00	34.50	
25	RIVER ROAD	D	115.00	13.20	
26	RIVER ROAD	D	230.00	34.50	
27	ROBERSONVILLE	D	12.50	4.16	
28	ROBERSONVILLE	D	115.00	12.50	
29	ROCKBRIDGE	D	46.00	12.50	
30	ROCKBRIDGE	D	115.00	13.20	
31	ROSEMONT	D	34.50	13.20	
32	ROSSLYN	D	69.00	13.20	
33	SANDBRIDGE	D	34.50	13.20	
34	SAPONY	D	115.00	34.50	
35	SAPONY	D	230.00	34.50	
36	SCOTLAND NECK	D	115.00	13.20	
37	SEABOARD	D	115.00	13.20	
38	SEAFORD	D	115.00	34.50	
39	SEWELLS POINT	T	230.00	115.00	13.20
40	SEWELLS POINT	D	230.00	34.50	13.20

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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1	SHACKLEFORD	D	115.00	34.50	
2	SHEA #1	D	34.50	13.20	
3	SHEA #1	D	34.50	4.16	
4	SHEA #2	D	115.00	34.50	13.20
5	SHELLBANK	D	230.00	23.00	
6	SHELLBANK	D	115.00	13.20	
7	SHELLBANK	T	230.00	115.00	13.20
8	SHERWOOD	D	115.00	34.50	
9	SHIRLEY DUKE	D	34.50	13.20	
10	SHOCKOE	D	115.00	34.50	
11	SHOCKOE	D	115.00	13.20	
12	SHORT PUMP	D	230.00	34.50	
13	SIDEBURN	D	230.00	34.50	
14	SINAI	D	115.00	12.50	
15	SISISKY	D	115.00	13.20	
16	SLIGO	D	230.00	34.50	13.20
17	SMITHFIELD	D	230.00	34.50	
18	SOMERSET	D	115.00	34.50	
19	SOUTH BOSTON	D	115.00	12.50	
20	SOUTH CREEK	D	34.50	12.50	
21	SOUTH CREEK	D	115.00	34.50	
22	SOUTH HILL	D	115.00	13.20	
23	SOUTH NORFOLK	D	34.50	13.20	
24	SOUTH NORFOLK	D	230.00	34.50	13.20
25	SOUTH WASHINGTON	D	34.50	4.16	
26	SOUTHWEST	D	230.00	34.50	
27	SPRINGFIELD	D	34.50	13.20	
28	ST ANDREW	D	13.20	4.16	
29	ST JOHNS	D	115.00	13.20	
30	ST JOHNS	T	230.00	115.00	13.20
31	STAFFORD	D	230.00	34.50	
32	STATE FARM	D	34.50	13.20	
33	STAUNTON	D	12.50	4.16	
34	STAUNTON	D	23.00	12.50	
35	STAUNTON	D	115.00	23.00	
36	STAUNTON	D	115.00	12.50	
37	STERLING PARK	D	230.00	34.50	
38	STONY CREEK	D	34.50	13.20	
39	STRATFORD HILLS	D	115.00	13.20	
40	STUART GARDENS	D	23.00	6.00	

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1	STUARTS DRAFT	D	115.00	23.00	
2	STUMPY LAKE	D	230.00	34.50	13.20
3	SUFFOLK	D	115.00	13.20	
4	SUFFOLK	D	115.00	34.50	
5	SUFFOLK	T	230.00	115.00	13.20
6	SUFFOLK	D	230.00	34.50	
7	SUFFOLK	T	500.00	230.00	
8	SULLY	D	230.00	34.50	
9	SUNBURY	D	230.00	34.50	
10	SUNSET HILLS	D	230.00	34.50	
11	SWINKS MILL	D	230.00	34.50	
12	TABB	D	230.00	34.50	
13	TAPPAHANNOCK	D	34.50	4.16	
14	TAR RIVER	D	115.00	12.50	
15	TARBORO	D	115.00	13.20	
16	TARBORO	T	230.00	115.00	13.20
17	TARBORO	T	230.00	115.00	
18	TAUSSIG	D	115.00	34.50	13.20
19	TAUSSIG	D	115.00	13.20	
20	TEMPLE AVE.	D	115.00	34.50	
21	THALIA	D	34.50	13.20	
22	THALIA	D	230.00	34.50	13.20
23	THIRD STREET	D	23.00	12.50	
24	THIRD STREET	D	23.00	4.16	
25	THOLE ST	D	115.00	34.50	13.20
26	THOMPSONS CORNER	D	115.00	34.50	13.20
27	THOMPSONS CORNER	D	115.00	13.20	
28	THRASHER	D	230.00	34.50	13.20
29	TIMBERVILLE	D	115.00	12.50	
30	TITUSTOWN	D	34.50	4.16	
31	TOANO	D	115.00	34.50	
32	TRABUE	D	230.00	34.50	
33	TRAP	D	34.50	13.20	
34	TREGO	D	12.50	2.40	
35	TREGO	D	115.00	2.40	
36	TROWBRIDGE	T	230.00	115.00	13.20
37	TUNIS	D	115.00	34.50	
38	TURNER	D	115.00	34.50	
39	TURNER	D	230.00	34.50	
40	TWELFTH ST.	D	115.00	34.50	

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1	TWELFTH ST.	D	115.00	13.20	
2	TWITTYS CREEK	D	34.50	12.50	
3	TWITTYS CREEK	D	115.00	34.50	
4	TYLER	D	230.00	34.50	
5	TYSONS	D	230.00	34.50	
6	UNIONVILLE DP	D	115.00	12.50	
7	VALLEY	T	500.00	230.00	
8	VAN DORN	D	230.00	34.50	
9	VERONA	D	115.00	23.00	
10	VICTORIA	D	115.00	12.50	
11	VIENNA	D	34.50	13.20	
12	VIRGINIA BEACH	D	115.00	34.50	13.20
13	VIRGINIA BEACH	D	115.00	13.20	
14	VIRGINIA BEACH	T	230.00	115.00	13.20
15	VIRGINIA HILLS	D	34.50	13.20	
16	VIRGINIA HILLS	D	230.00	34.50	
17	WAKEFIELD	D	13.20	4.16	
18	WAKEFIELD	D	115.00	34.50	
19	WAKEFIELD	D	115.00	13.20	
20	WALLER	D	230.00	34.50	
21	WALNEY	D	230.00	34.50	
22	WALNUT HILL	D	13.20	4.16	
23	WALTHALL	D	115.00	34.50	
24	WAN	D	115.00	34.50	
25	WAR	D	69.00	13.20	
26	WARRENTON	D	230.00	34.50	
27	WARSAW	D	34.50	13.20	
28	WARWICK	D	115.00	13.20	
29	WARWICK	D	230.00	34.50	
30	WATKINS CORNER	D	115.00	34.50	
31	WAVERLY	D	115.00	13.20	
32	WAYNE HILLS	D	23.00	12.50	
33	WAYNESBORO	D	115.00	23.00	
34	WELCO	D	115.00	34.50	
35	WELCO	D	115.00	12.50	
36	WESCOTT	D	34.50	13.20	
37	WEST LANDING	D	230.00	34.50	13.20
38	WEST STAUNTON	D	230.00	23.00	
39	WESTHAVEN	D	34.50	4.16	
40	WESTMINSTER	D	34.50	13.20	

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WESTMORELAND	D	230.00	34.50	
2	WESTPOINT	D	115.00	34.50	
3	WEYERS CAVE	D	115.00	34.50	
4	WHEALTON	T	230.00	115.00	13.20
5	WHITAKERS	D	115.00	34.50	13.20
6	WHITEHALL DP	D	34.50	23.00	
7	WHITESTONE	D	115.00	12.50	
8	WILLIAMSBURG	D	34.50	13.20	
9	WILLOUGHBY	D	34.50	13.20	
10	WILLSTON	D	34.50	13.20	
11	WINCHESTER	D	34.50	13.20	
12	WINCHESTER	D	230.00	34.50	
13	WINFALL	D	115.00	34.50	
14	WINFALL	T	230.00	115.00	13.20
15	WINTERPOCK	D	230.00	34.50	
16	WOODBRIDGE	D	230.00	34.50	
17	WOODLAND	D	115.00	34.50	
18	WOODSTOCK	D	34.50	12.50	
19	WYTHE	D	23.00	6.00	
20	YADKIN	T	230.00	115.00	13.20
21	YADKIN	D	230.00	34.50	
22	YADKIN	T	500.00	230.00	34.50
23	YADKIN	T	500.00	230.00	
24	YORKTOWN	T	230.00	115.00	13.20
25	Total Transmssn & Distribution		91910.20	24948.06	1555.56
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
195	3					1
80	2					2
22	1					3
7	1					4
22	1					5
20	1					6
13	2					7
11	1					8
224	2					9
112	1					10
20	1					11
90	2					12
34	1					13
42	2					14
327	4					15
95	2					16
150	2					17
3	3					18
40	2					19
100	2					20
40	2					21
50	1					22
168	1					23
84	1					24
22	1	1				25
150	2					26
22	1					27
448	2					28
168	2					29
40	2					30
13	1					31
20	1					32
56	1					33
22	1					34
112	1					35
234	3					36
159	2					37
14	1					38
20	1					39
168	2					40

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

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13	1					1
87	2					2
22	1					3
10	4					4
100	2					5
5	1					6
75	1					7
13	1					8
22	1					9
168	2					10
84	1					11
22	1					12
192	4	1				13
224	1					14
8	3					15
840	3	1				16
224	1					17
13	1					18
52	2					19
13	6	1				20
11	1					21
34	1	1				22
9	1					23
45	2					24
336	2					25
159	2					26
56	1					27
6	1					28
11	1					29
22	1					30
100	1					31
80	2					32
224	1					33
14	1					34
840	3	1				35
840	3					36
13	1					37
50	1					38
120	3					39
34	1					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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90	3	1				1
22	1					2
35	2					3
134	2					4
106	2					5
269	3	1				6
67	2					7
13	1					8
150	2					9
14	1					10
11	3					11
14	1					12
14	1					13
224	1					14
840	3	1				15
22	1					16
22	1					17
22	1					18
224	1					19
150	2					20
129	2					21
64	2					22
159	2					23
168	1					24
234	3					25
22	1					26
1680	6	1				27
20	1					28
22	1					29
250	1					30
1680	6	2				31
168	1					32
56	3	1				33
5	1					34
168	2					35
22	1					36
5	1					37
15	1					38
3	1					39
45	2					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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34	1					1
24	2					2
25	2					3
67	2					4
67	2					5
6	3	1				6
120	2					7
5	1					8
22	1					9
22	1					10
50	1					11
5	1					12
67	1					13
598	4					14
85	2					15
22	1					16
5	1					17
95	2					18
42	2					19
100	2					20
45	2					21
6	1					22
129	2					23
14	1					24
4	1					25
6	1					26
22	1					27
96	2					28
673	3					29
1680	6	1				30
10	1					31
42	2					32
243	3					33
11	1					34
2	1					35
159	2					36
125	2					37
84	2					38
20	1					39
4	3	1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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45	2					1
168	1					2
5	3					3
24	2					4
62	2					5
6	1					6
100	2					7
112	1					8
5	1					9
159	2					10
118	2					11
22	2					12
336	2					13
95	2					14
1680	6	1				15
22	1					16
45	2					17
448	2					18
42	2					19
22	1					20
50	1					21
448	2					22
100	2					23
45	2					24
10	1					25
42	2					26
168	2					27
45	2					28
336	2					29
25	1					30
75	1					31
1680	6					32
45	2					33
13	1					34
40	2					35
45	2					36
9	1					37
20	1					38
5	1					39
168	2					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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45	2					1
75	1					2
42	2					3
392	2					4
84	1					5
393	4	1				6
118	2					7
159	2					8
84	1					9
8	1					10
5	1					11
22	1					12
22	1					13
159	2					14
225	3					15
11	1					16
22	1					17
448	2					18
30	3	1				19
13	1					20
5	1					21
50	1					22
67	2					23
67	2					24
5	1					25
196	2					26
234	3					27
448	2					28
50	1					29
9	3	1				30
9	1					31
13	1					32
22	1					33
224	1					34
14	1					35
9	1					36
159	2					37
448	2					38
84	1					39
6	3					40

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SUBSTATIONS (Continued)

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20	1					1
50	1					2
67	2					3
22	1					4
168	3	1				5
75	1					6
56	2					7
224	1					8
224	6	1				9
45	2					10
45	1					11
74	2					12
45	2					13
224	1					14
159	2					15
75	1					16
14	1					17
50	1					18
22	1					19
112	1					20
28	2					21
9	3					22
50	1					23
20	1					24
4	1					25
22	1					26
45	1					27
80	2					28
392	5					29
45	1					30
42	2					31
45	1					32
134	3					33
150	2					34
14	1					35
336	2					36
11	1					37
9	1					38
124	2					39
45	2					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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140	3					1
6	1					2
5	3					3
8	3					4
6	1					5
318	4					6
22	1					7
196	4					8
22	1					9
14	1					10
20	1					11
7	1					12
40	1					13
14	1					14
25	1					15
56	1					16
50	1					17
13	1					18
112	2					19
504	3	1				20
75	1					21
5	3					22
840	3	1				23
6	1					24
22	1					25
5	1					26
90	2					27
56	2					28
392	2					29
159	2					30
56	1					31
42	2					32
22	1					33
448	2					34
125	2					35
14	1					36
336	2					37
9	2					38
20	1					39
13	1					40

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SUBSTATIONS (Continued)

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22	1					1
22	1					2
7	1					3
33	2					4
13	1					5
5	1					6
336	2					7
672	6	1				8
234	3					9
14	1					10
22	1					11
56	1					12
42	2					13
336	2					14
56	1					15
78	2					16
336	2					17
1680	6	2				18
45	1					19
106	4	1				20
250	1	1				21
42	2					22
131	2					23
7	6	1				24
45	2					25
22	1					26
106	2					27
7	1					28
3	3					29
9	1					30
11	1					31
4	1					32
106	2					33
42	2					34
40	2					35
22	1					36
50	1					37
40	2					38
22	1					39
14	1					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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96	3					1
4	1					2
159	2					3
840	3					4
120	2					5
5	1					6
2220	6	1				7
50	1					8
22	1					9
125	2					10
22	1					11
45	2					12
22	1					13
113	6					14
50	1					15
4	1					16
5	3					17
224	2	1				18
168	2					19
34	1					20
672	6	1				21
50	1					22
22	2					23
42	2					24
224	1					25
224	2					26
56	2					27
336	4					28
34	1					29
22	1					30
168	1					31
252	3					32
5	1					33
95	2					34
45	2					35
168	3					36
42	2					37
150	2					38
9	2					39
6	1					40

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5	1					1
50	1					2
22	1					3
22	1					4
45	2					5
1680	6	2				6
13	1					7
6	3	1				8
42	2					9
13	1					10
13	1					11
34	1					12
75	1					13
252	3					14
112	2					15
11	1					16
45	2					17
224	1					18
45	1					19
34	1					20
504	3					21
45	2					22
5	3					23
13	1					24
17	2					25
42	2					26
168	1					27
56	1					28
225	3					29
840	3	1				30
45	2					31
67	2					32
336	2					33
159	2					34
34	1					35
50	1					36
22	1					37
9	2					38
224	1					39
336	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
840	3	1				1
6	3					2
100	2					3
5	1					4
168	1					5
22	1					6
56	1					7
9	1					8
32	2					9
20	1					10
42	2					11
84	1					12
45	2					13
75	1					14
84	1					15
22	1					16
252	3					17
392	2					18
67	2					19
224	1					20
224	1					21
12	2					22
234	3					23
22	1					24
42	2					25
168	2					26
11	2					27
13	1					28
11	3	3				29
56	2					30
6	1					31
134	4					32
20	1					33
22	1					34
34	1					35
22	1					36
14	3	1				37
45	2					38
448	2					39
168	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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34	1					1
20	1					2
6	1					3
100	2					4
168	2					5
22	1					6
224	1					7
100	2					8
45	2					9
120	2					10
90	2					11
225	3					12
75	1					13
22	1					14
22	1					15
50	1					16
106	2					17
22	1					18
35	2					19
11	1					20
22	1					21
45	2					22
22	1					23
100	1					24
6	3					25
224	2					26
42	2					27
5	1					28
13	1					29
168	1					30
159	2					31
6	1					32
7	1					33
9	1					34
42	4					35
20	1					36
243	3					37
4	1					38
45	2					39
5	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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47	2					1
159	2					2
40	3	1				3
22	1					4
448	2					5
75	1					6
1680	6	1				7
150	2					8
25	1					9
84	1					10
120	2					11
129	2					12
3	1					13
22	1					14
20	1					15
112	1					16
112	1					17
56	1					18
22	1					19
22	1					20
40	2					21
224	2					22
9	1					23
4	3					24
56	1					25
140	2					26
42	2					27
224	3					28
20	1					29
5	1					30
56	2					31
120	2					32
6	1					33
3	3					34
6	1					35
336	2					36
56	2					37
45	1					38
45	1					39
168	2					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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150	2					1
6	1					2
22	1					3
168	2					4
309	4					5
13	1					6
840	3	1				7
150	2					8
25	2					9
14	1					10
42	2					11
168	2					12
42	2					13
448	2					14
36	2					15
159	2					16
3	1					17
13	1					18
9	1					19
159	2					20
150	2					21
4	1					22
34	1					23
78	4	1				24
37	1					25
134	2					26
9	1					27
40	2					28
150	2					29
20	1					30
33	2					31
11	1					32
50	1					33
22	1					34
15	1					35
40	2					36
34	1					37
134	2					38
7	2					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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34	1					1
56	2					2
22	1					3
448	2					4
22	1					5
8	1					6
14	1					7
14	1					8
13	1					9
14	1					10
67	2					11
150	2					12
45	2					13
168	1					14
134	2					15
168	2					16
22	1					17
6	2					18
5	3					19
224	1					20
75	1					21
840	3	1				22
840	3	1				23
224	1					24
77319	1090	48				25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

NC IRP 2013 UPDATE

ADDENDUM 3

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2012

Schedule I. Identification and Certification

1. **Respondent Identification:**

Code: 19876 **Name:** Virginia Electric & Power Co

2. **Responses Provided:**

[✓] **Parts 2, 5 and 6:**

Submitted by: SERC Reliability Corporation

Contact Person: Ben Crisp

Title: Director of Assessment

Telephone: (704) 940-8237

Facsimile: (704) 357-7914

e-mail: bcrisp@serc1.org

[✓] **Parts 3 and 4 :**

Transmitting Utility: Virginia Electric & Power Company
One James River Plaza
701 E. Cary St
Richmond, Virginia 23219

3. **Respondent Mailing Address:**

Mehdi Shakibafar
Virginia Electric & Power Company
701 East Cary Street
Richmond, Virginia 23219
e-mail: Mehdi.shakibafar@dom.com

4. **Contact Person:**

Name: Mehdi Shakibafar, P.E.

Title: Consulting Engineer

Telephone: (804) 771-4861

Facsimile: (804) 771-4548

5. **Certifying Official:**

Name: Kevin Curtis

Title: Dir. Electric Transmission Planning

Signature: ________________

Date: 03/26/13

Return Completed Form to: **Federal Energy Regulatory Commission**
Secretary of the Commission
Form No. 715
888 First Street N.E.
Washington, D.C. 20426

Part II Regional or Subregional Power Flow Base Cases
Schedule I
Authorization for the release of most current Power Flow Data Models

Virginia Electric & Power Company (the Company) is a member of the SERC Reliability Corporation (SERC) and participates in its regional process for consolidating and sharing of power flow information. As such, the Company authorizes the SERC to release, without conditions, to FERC the most current regional power flow models.

Part 2: Power Flow Base Cases:

The following cases are available and are filed electronically with FERC:

1. 2013 Light Load	ERAG-MMWG	8. 2014 Summer	ERAG-MMWG
2. 2013 Spring	ERAG-MMWG	9. 2014 Winter	ERAG-MMWG
3. 2013 Summer	ERAG-MMWG	10. 2018 Light Load	ERAG-MMWG
4. 2013 Summer Shoulder	ERAG-MMWG	11. 2018 Summer	ERAG-MMWG
5. 2013 Winter	ERAG-MMWG	12. 2018 Winter	ERAG-MMWG
6. 2013 Fall	ERAG-MMWG	13. 2023 Summer	ERAG-MMWG
7. 2014 Spring	ERAG-MMWG		

These cases are provided on the CDROM. The CDROM contains the following information: Input data in PTI (Power Technologies, Inc.) PSS/E Raw Data File (.RAW) format; corresponding output data files in ASCII format showing solved real and reactive power flows and other relevant output information; and a SERC Data Dictionary that cross-references bus names.

Areas outside SERC contain equivalent representations not intended for study of the transmission systems in those areas. In addition, some future transmission and generation facilities in these cases are for planning purposes only and have not been authorized for the individual systems. The databases provided are not detailed models of individual systems and may not be appropriate for individual system studies.

These files have been reviewed for accuracy; however, the integrity of such data cannot be guaranteed after its release due to the possible unintentional erroneous transfer of data from SERC's files or other external factors that may alter the data once it is downloaded to this storage medium. Although the disc was scanned by the originator using state-of-the-art anti-virus software, the recipient is responsible for taking steps to protect against any potential computer virus, defective disc-reading device, or other problems that may occur when reviewing this file.

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2012

Part III - Schedule I Transmitting Utility Maps and Diagrams

Map identifying Items A, B, C, D, and E (as requested in Part III item 2) are attached.

A. Generating Plants
B. Switching Stations
C. Substations
D. Service Areas, and
E. Interconnections with other utilities.

Included (and attached separately) are Dominion Virginia Power/North Carolina Power's most recent single-line schematic diagrams identifying:

A. AC and DC transmission lines and facilities, including their nominal operating and design voltages,
B. Electrical connections
C. Generating plants
D. Transformation facilities,
E. Phase angle transformers, and
F. VAR control equipment, i.e., shunt and series capacitors and inductors, etc.

Federal Energy Regulatory Commission
Form FERC-715 (2012)

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2012

Utility Code: 19876
Utility Name: Virginia Electric & Power Co

Part IV - Schedule I, Transmission Planning Reliability Criteria

Please see the attached PDF document titled: "2013 Form 715 for DVP part IV – Transmission Planning Criteria"

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2012

Part V - Schedule I, Application of Assessment Practice

Terms and Conditions

There have been no changes since last filed

Reasonable Action

There have been no changes since last filed

Critical Loads

There have been no changes since last filed

Considerations

There have been no changes since last filed

Improving Outage Frequency

There have been no changes since last filed

Improving Outage Duration

There have been no changes since last filed

Part V - Schedule II Procedure for Assessment Practice

General procedures in use by Dominion Virginia Power/North Carolina Power to assess the transmission system:

1. Base case parameters for the conditions under study are established. The most common situation studied is the projected peak load for a particular year, although studies at other than peak loads are also conducted. Loads, generation dispatch, power interchange, and system improvements are modeled in the base case for the year and conditions under study.

2. A list of outaged and monitored facilities is developed. For internal studies, all of the transmission facilities in the area under study are usually outaged and monitored. For regional/subregional studies, certain selected facilities are outaged and all bulk power facilities are monitored.

3. When power transfers with other entities are being studied, generation dispatches and scheduled power interchange for the involved parties are modeled.

4. A linear power flow program ("DC" power flow) is used as a screening tool to determine line flows for the modeled transfers and/or simulated facility outages. The program currently being used is the Power Technologies, Inc. (PTI) PSSE/E Power Flow Program and MUST.

5. The output of the linear power flow is analyzed for overloaded facilities. Transfer capabilities between entities are calculated in accordance with the NERC document, "Transmission Transfer Capability" dated May 1995.

6. If a more detailed analysis is required, AC power flow studies are conducted using the PTI PSS/E Power Flow Program.

7. The results of the above studies are compared with the planning criteria. In some instances, a formal report is written documenting the study results.

Special studies are required to analyze particular situations. Some examples are transient stability, voltage and reactive control, steady state stability, and inertial power flow studies.

Virginia Power participates in SERC Intra-Regional Near-Term Study Group (NTSG)), and SERC Intra-Regional Long-Term Study Group (LTSG). The NTSG and LTSG study groups have procedural manuals that detail work procedures and practices. These manuals are being submitted by the office of the SERC Reliability Corporation (SERC) and are to be considered a part of Virginia Power's response to Part 5.

Part V - Schedule III Critical Facilities Listing

The Company tests single contingencies of all its branches, including all Tie Lines.

Part V - Schedule IV NERC Planning Standards and SERC Supplements

The following documents were filed in hard copy and electronically by SERC in past years and have been on file at FERC and in the regional reliability organization office. The current revisions of these documents (Adobe Acrobat Format) are included in the present filing. They may also be referenced by the individual SERC member systems in their filings under this Part 5.

1. Current SERC NTSG Procedural Manual
2. Current SERC LTSG Procedural Manual
3. Current ERAG Study Procedural Manual

The SERC Region has adopted the NERC reliability standards and Rules of Procedure as its basis for planning the bulk electric power system. SERC guidelines and regional criteria have been written to clarify and augment the requirements of the NERC reliability standards as they are applied to the SERC Region and its members. These guidelines and regional criteria are posted on the SERC website (www.serc1.org/documents/serc).

Part VI - Schedule I Evaluation of Transmission Performance

Virginia Power participates in the following regional/subregional study groups with other utilities: SERC Intra-Regional Long-Term Study Group (LTSG), and SERC Intra-Regional Near-Term Study Group (NTSG)

Reports on the evaluation of transmission system performance for future time periods, including the upcoming summer and winter peak load seasons, are issued by the above groups. The most recent reports of these study groups are being submitted by the SERC Reliability Corporation (SERC) office and are considered to be part of Virginia Power's response to Part 6:

1. 2012-13 ERAG Winter Transmission System Reliability Assessment (November 2012)
2. 2012 ERAG Summer Transmission System Reliability Assessment (May 2012)
3. SERC Engineering Committee Near-term Study Group (NTSG) 2012 Summer Reliability Study of Projected Operating Conditions (June 2012)
4. SERC NTSG 2012/2013 Winter Reliability Study of Projected Operating Conditions (November 2012)
5. SERC Engineering Committee Long-term Study Group (LTSG) 2016 Summer Future Year Study (December 2012)

Federal Energy Regulatory Commission Form FERC-715 (2012)	**Annual Transmission Planning and Evaluation Report For the Year Ending December 31, 2012**	**Utility Code: 19876 Utility Name: Virginia Electric & Power Co**

Part VII Checklist

__√___ All parts of the FERC Form No. 715 must be completed. Blank or N/A responses are not acceptable. If there are no changes from previously submitted information of Parts 3, 4 or 5, then please provide a statement to that effect.

__√___ One electronic copy of Parts 1, 3, 4, 5 and 6 of the FERC Form No. 715.

______ One electronic copy of Part 2 of the FERC Form No. 715 - **Supplied by SERC Reliability Corporation (SERC)**