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May 1, 2020

VIA ELECTRONIC DELIVERY

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603-5918

Re: Docket No. E-100 Sub 165
2020 Integrated Resource Plan of Virginia Electric and Power Company

Dear Ms. Campbell:

Pursuant to §§ 62-2 and 62-110.1 of the North Carolina General Statutes and Rule R8-60(h)(1) of the Rules and Regulations of the North Carolina Utilities Commission (the "Commission"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company"), encloses for electronic filing with the Commission the Public version of its 2020 Integrated Resource Plan (the "2020 Plan"). The Company is filing the 2020 Plan contemporaneously with the filing of its 2020 Plan in its Virginia jurisdiction, pursuant to Va. Code § 56-599.

Portions of this 2020 Plan contain confidential information, are designated by DENC as confidential, and qualify as "trade secret" under N.C.G.S. § 66-152(3). Pursuant to N.C.G.S. § 132-1.2, DENC is filing these pages separate from this filing and under seal.

Enclosed with the electronic filing of this 2020 Plan is the public version of the NC Plan Addenda 1-3. NC Plan Addendum 1 is the public (redacted) version of the Company's 2020 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 Plan Addendum 2 contains pages 424 and 425 of the Company's most recently-filed Federal Energy Regulatory Commission ("FERC") Form 1 and is being provided with the 2020 Plan pursuant to Rule R8-62(p)(1). As pages 422 and 423 of the Company's most recently-filed FERC Form 1 were included with DENC's 2017 Integrated Resource Plan, those pages are not included with this 2020 Plan as permitted by Rule R8-62(p)(1). Information contained in NC Plan Addendum 2 is entirely public.

NC Plan Addendum 3 contains the public (redacted) version of the Company's most recently completed FERC Form 715, including all attachments and exhibits, as required by the Commission in previous orders. The maps attached to FERC Form 715 are considered confidential because they contain critical energy infrastructure information, including the Company's transmission capacity and known constraints, and therefore have been redacted. The Company's practice in prior years has been to file by hand under separate cover four (4) paper copies of the most recent FERC Form 715, with the attached maps to be maintained as confidential filed under seal. Due to the current suspension of the requirement to file paper copies, *see* the Commission's *Order Further Extending Suspension of Requirement for Filing Paper Copies* issued on April 16, 2020, in Docket No. M-100, Sub 158, the Company plans to file the paper copies of its most recent FERC Form 715 once the paper filing suspension has lifted, on or before September 1, 2020. The Company has discussed this plan with the Public Staff and the Public Staff does not oppose it.

In accordance with Ordering Paragraph (3) of the Commission's June 3, 2013 Order Granting in Part and Denying in Part Motion for Disclosure issued in Docket No. E-100, Sub 137, the Company has reviewed its 2016 REPS Compliance Plan for any redacted information that no longer qualifies as "trade secrets" under N.C. Gen. Stat. § 66-152(3), and is simultaneously filing an updated 2016 REPS Plan under separate cover letter in Docket Nos. E-100, Sub 147 and E-100, Sub 165, consistent with that requirement.

Included with this filing letter is a reference index identifying the provisions of the Commission's integrated resource planning requirements under prior Commission Orders and Rules with the corresponding sections of the 2020 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 confer 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 Rule R8-60(m), the Company will notify parties of record to this proceeding as well as any non-parties that attended DENC's 2019 integrated resource planning Stakeholder Review meeting of the time and place for its 2020 integrated resource planning Stakeholder Review meeting to be held on or before November 30, 2020.

Therefore, please find enclosed for electronic filing the Public version of the 2020 Plan, including NC Plan Addenda 1- 3, with the confidential information redacted, as appropriate.

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

Very truly yours,

/s/*Andrea R. Kells*

ARK:kjg

Enclosures

cc: Lucy Edmondson, Public Staff—North Carolina Utilities Commission
Layla Cummings, Public Staff—North Carolina Utilities Commission
Nadia L. Luhr, Public Staff—North Carolina Utilities Commission

Virginia Electric and Power Company
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(1) E-100, Sub 109, OP6	**Appendix 5B**
(1) E-100, Sub 109, OP7	**Filing Letter** **Section 5.5.2** Levelized Busbar Costs
(1) E-100, Sub 109, OP8	**Appendix 4K**
(1) E-100, Sub 109, OP9	**Chapter 6** Generation - Demand-Side Management
(8) E-100, Sub 84, OP5	**Section 9.4** Economic Development Rates
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(9) E-100, Sub 133, OP4 (10) E-100, Sub 137, OP10 (5) E-100, Sub 137, OP9 (6) E-100, Sub 141, OP9	**Section 4.1** Load Forecast
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(10) E-100, Sub 137, OP16 (5) E-100, Sub 137, OP13 (6) E-100, Sub 141, p. 38 (6) E-100, Sub 141, OP13 (7) E-100, Sub 147, p. 47	**Section 2.2** Alternative Plans
(10) E-100, Sub 137, OP14 (10) E-100 Sub 137, pp. 35-36	**Section 5.5** Future Supply-Side Generation
(7) E-100, Sub 147, pp. 60-61 (12) E-100, Sub 157, pp. 58-59	**Section 4.7** Storage-Related Assumptions **Section 5.5.1** Supply-Side Resource Options
(5) E-100, Sub 137, p. 39	**2020 Plan**
(5) E-100, Sub 137, p. 41	**Section 1.3** Regional Greenhouse Gas Initiative **Section 1.1** Other Environmental Regulations **Section 5.2.3** Environmental Regulations
(7) E-100, Sub 147, p. 49	**Section 5.4.4** Extension of Nuclear Licenses
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Rule R8-60 (f) (12) E-100, Sub 157 pp. 32-35, 38	**Chapter 6** Generation - Demand-Side Management
Rule R8-60 (g)	**Chapter 2** Results of Integrated Planning Process
Rule R8-60 (h) (3)	**Chapter 3** Short-Term Action Plan
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Rule R8-60 (i) (9)	**Section 5.5.2** Levelized Busbar Costs / Levelized Cost of Energy
Rule R8-60 (j)	**N/A**
Rule R8-60 (m)	**Filing Letter**
Rule R8-62 (p) (1)	**NC Plan Addendum 2** FERC Form 1
Rule R8-62 (p) (2)	**N/A**
Rule R8-62 (p) (3)	**N/A**
NCGS § 62-133.9 (c)	**Chapter 6** Generation – Demand-Side Management

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Note No.	Order
1	Order Approving Integrated Resource Plans, Docket No. E-100, Sub 109 (July 9, 2007)
2	Order Approving 2008 and 2009 Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Subs 118, 124 (August 10, 2010)
3	Order Approving 2010 Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 128 (October 26, 2011)
4	Order Approving 2011 Annual Updates to 2010 Integrated Resource Plans and 2011 REPS Compliance Plans, Docket No. E-100, Sub 128 (May 30, 2012)
5	Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, Docket No. E-100, Sub 137 (June 30, 2014)
6	Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100 Sub 141 (June 26, 2015)
7	Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147 (June 27, 2017)
8	Order Adopting Integrated Resource Plans, Docket No. E-100, Sub 84 (June 21, 2000)
9	Order Denying Rulemaking Petition, Docket No. E-100, Sub 133 (October 30, 2012)
10	Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 137 (October 14, 2013)
11	Order Granting in Part and Denying in Part Motion for Disclosure, Docket No. E-100, Sub 137 (June 3, 2013)
12	Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, Docket No. E-100, Sub 157 (August 27, 2019)

Virginia Electric and Power Company's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2020-00035
Docket No. E-100, Sub 165

Filed: May 1, 2020

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List of Acronyms

Acronym	Meaning
2018 Plan	2018 Integrated Resource Plan
2019 Update	2019 Update to the 2018 Plan
2020 Plan	2020 Integrated Resource Plan
AC	Alternating Current
ACE Rule	Affordable Clean Energy Rule
AMI	Advanced Metering Infrastructure
BDM	Bass Diffusion Model
BESS	Battery Energy Storage System
BSER	Best System of Emissions Reduction
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CC	Combined-Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture and Sequestration
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
COD	Commercial Operation Date
COL	Combined Operating License
Company	Virginia Electric and Power Company
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
CVOW	Coastal Virginia Offshore Wind
CWA	Clean Water Act
DAC	Direct Air Capture
DC	Direct Current
DER	Distributed Energy Resource(s)
DOM LSE	Dominion Energy Load Serving Entity
DOM Zone	Dominion Energy Zone
DSM	Demand-Side Management
DynADOR	Dynamic Assessment and Determination of Operating Reserves
EC	Enactment Clause
ECR	Emission Containment Reserve
EE	Energy Efficiency
EGU	Electric Generating Unit(s)
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines

Acronym	Meaning
EO43	Virginia Executive Order 43
EO80	North Carolina Executive Order 80
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FACTS	Flexible Alternative Current Transmission System
FERC	Federal Energy Regulatory Commission
FERC MOPR Order	June 29, 2018 FERC Order on MOPR
FRR	Fixed Resource Requirement
FSEIS	Final Supplemental Environmental Impact Statement
GHG	Greenhouse Gas
GTSA	Grid Transformation and Security Act of 2018
GW	Gigawatts
GWh	Gigawatt Hours
HVDC	High-voltage Direct Current
ICF	ICF Resources, LLC
IDP	Integrated Distribution Planning
IEEE	Institute of Electrical and Electronics Engineers
IHS	IHS Markit
IPP	Independent Power Producer(s)
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt Hours
LCOE	Levelized Cost of Energy
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MGD	Million Gallons per Day
MMBtu	Million British Thermal Unit(s)
Moody's	Moody's Analytics
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NCDEQ	North Carolina Department of Environmental Quality
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
Net CONE	Net Cost of New Entry
NO_x	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	The National Renewable Energy Laboratory

Acronym	Meaning
NSRDB	National Solar Radiation Database
NUG	Non-Utility Generation or Non-Utility Generator
O&M	Operations and Maintenance
ODEC	Old Dominion Electric Cooperative
PJM	PJM Interconnection, L.L.C.
Plan	Integrated Resource Plan
PLEXOS	PLEXOS Model
PPA	Power Purchase Agreement
ppb	Parts Per Billion
PTC	Production Tax Credit
RACT	Reasonable Available Control Technology
RAIs	Requests for Additional Information
REC	Renewable Energy Certificate(s)
REPS	N.C. Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable Natural Gas
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	Virginia State Corporation Commission
SCPC	Supercritical Pulverized Coal
SER	Safety Evaluation Report
SG	Standby Generation
SMR	Small Modular Reactor
SO_2	Sulfur Dioxide
STATCOM	Static Synchronous Compensators
Study Period	25-year Period of 2021 to 2045
SUP	Strategic Underground Program
TRC	Total Resource Cost
V2G	Vehicle-to-grid
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act
VCHEC	Virginia City Hybrid Energy Center
VDEQ	Virginia Department of Environmental Quality
WHP	Waste Heat to Power

Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.6 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company is a subsidiary of Dominion Energy, Inc. ("Dominion Energy")—one of the nation's largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 20 states with electricity or natural gas.

The Company's supply-side portfolio consists of 20,063 megawatts ("MW") of generation capacity, including approximately 812 MW of non-utility generation ("NUG") resources. The Company's demand-side management ("DSM") portfolio consists of energy efficiency and demand response programs in Virginia and North Carolina. The Company owns approximately 6,800 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV in Virginia, North Carolina, and West Virginia; and approximately 58,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia and North Carolina. The Company is a member of PJM Interconnection, LLC ("PJM") Regional Transmission Organization ("RTO"), the operator of the wholesale electric grid in the Mid-Atlantic region of the United States. The 2020 Integrated Resource Plan (the "2020 Plan" or the "Plan") was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") within PJM.

The Company files this 2020 Plan with the Virginia State Corporation Commission ("SCC") in accordance with § 56-597 *et seq*. of the Code of Virginia (or "Va. Code") and the SCC's guidelines issued on December 23, 2008. The Company also files this 2020 Plan with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of NCUC's Rules and Regulations. The 2020 Plan also addresses requirements identified by the SCC and the NCUC in prior relevant orders, as well as current and pending provisions of state and federal law.

This 2020 Plan covers the 15-year period beginning in 2021 and continuing through 2035 (the "Planning Period"), using 2020 as the base year. In certain instances, the Company evaluates the longer 25-year period of 2021 to 2045 (the "Study Period"). Overall, the 2020 Plan is a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections, and should be viewed in that context.

Executive Summary

Throughout its history, the Company has been dedicated to the delivery of safe, reliable, and affordable energy to its customers. This dedication has included a strong movement towards a clean environment. For example, over the last two decades, by changing its generation mix and employing best practices, the Company's power generation fleet has reduced certain air emissions, including nitrogen oxide, sulfur dioxide, and mercury, by as much as 99%. The Company has also reduced its greenhouse gas emissions, lowering its carbon intensity by approximately 47% since 2000. Further, by adopting the latest technology and applying creative design, the Company is using less water in its operations through the use of air-cooled condensers.

The Company has now entered a new phase in its overall efforts to preserve the environment. On February 11, 2020, the Company's parent company—Dominion Energy—announced a significant expansion of its greenhouse gas emissions reduction goals, establishing a new company-wide commitment to achieve net zero carbon dioxide ("CO_2") and methane emissions by 2050. Net zero does not mean eliminating all emissions, but instead means that any remaining emissions are balanced by removing an equivalent amount from the atmosphere. For example, this can occur through carbon capture, reforestation, or negative-emissions technologies such as renewable natural gas. This strengthened commitment to net zero CO_2 and methane emissions builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions consistent with the findings of the United Nations' Intergovernmental Panel on Climate Change. The commitment is also a recognition of the increased expectations and interest among customers, policy makers, and employees in building a clean energy future.

This net zero CO_2 and methane emissions commitment from Dominion Energy parallels the commitments made to clean energy in both Virginia and North Carolina. In Virginia, the Virginia Clean Economy Act (the "VCEA") will become law effective July 1, 2020. The VCEA establishes a mandatory renewable portfolio standard ("RPS") aimed at 100% clean energy from the Company's generation fleet by 2045. In furtherance of this mandatory RPS, the VCEA requires the development of significant energy efficiency, solar, wind, and energy storage resources; it also mandates the retirement of all generation units that emit CO_2 as a byproduct of combustion by 2045, unless the retirement of a particular unit would threaten grid reliability and security. Based on other new legislation, the Company expects that Virginia will soon become a full participant in the Regional Greenhouse Gas Initiative ("RGGI")—a regional effort to cap and reduce CO_2 emissions from the power sector. In North Carolina, the Clean Energy Plan, a compilation of policy and action recommendations developed through a public stakeholder process, sets a statewide carbon neutrality goal by 2050.

This 2020 Plan focuses on presenting alternative plans that set the Company on a trajectory to achieve these clean energy targets. Indeed, the Company has already begun to transition its generation fleet, as well as its transmission and distribution systems, to achieve a cleaner future. Examples of this ongoing transition include:

- The retirement of over 2,200 MW of coal-fired and inflexible, higher cost oil- and natural gas-fired generation over the past ten years;
- The construction of approximately 198 MW of solar generation over the past ten years, with an additional 198 MW of solar generation currently under construction;
- The procurement of approximately 874 MW of solar NUGs over the past ten years;
- The continued work to extend the licenses of the Company's nuclear units at Surry and North Anna;
- The construction of the Coastal Virginia Offshore Wind ("CVOW") demonstration project, along with the development of a larger build-out of offshore wind generation off the coast of Virginia;
- The continued transformation of the Company's distribution grid to provide an enhanced platform for distributed energy resources ("DERs") and targeted DSM programs; more secure and reliable service, leading to the increased availability of DERs; and more ways for customers to save energy and money through DSM programs and other rate offerings; and
- The continued work associated with energy storage technology, including the development of a new pumped storage hydroelectric facility in Virginia and the deployment of three battery energy storage system ("BESS") pilot projects.

Over the long term, however, achieving the clean energy goals of Virginia, North Carolina, and the Company will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. This includes support for the testing and deployment of technologies such as large-scale energy storage, hydrogen, advanced nuclear, and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

In this 2020 Plan, the Company presents four alternative plans (the "Alternative Plans"). Except for Alternative Plan A, all Alternative Plans assume that Virginia is a full RGGI participant.

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues. While Plan B—and indeed all Alternative Plans—incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Study Period. Overall, Plan B is the lowest cost of Alternative Plans B, C, and D, decreases the reliance on outside markets to meet customer demand and produces similar regional CO_2 emissions as Plans C and D. Over the Study Period (*i.e.*, 2021 to 2045), this Alternative Plan includes the development of approximately 31 gigawatts ("GW") of solar capacity, approximately 5 GW of offshore wind capacity, and approximately 5 GW of new energy storage.

- Plan C – This Alternative Plan uses similar assumptions as Plan B, but retires all Company-owned carbon-emitting generation in 2045, resulting in close to zero CO_2 emissions from the Company's fleet in 2045. To reach zero CO_2 emissions from the Company's fleet in 2045, Plan C significantly increases the amount of energy storage resources and the level of imported power. Specifically, in the last ten years of the Study Period, Plan C requires the addition of approximately 1 GW of incremental solar capacity and approximately 4.8 GW of incremental energy storage as compared to Plan B. In addition, beginning in Year 16 of Plan C, the Company's transmission import capacity would need to double to approximately 10.4 GW total in order to support the Company's winter import needs, as well as spring and fall export needs. This imported power from PJM would come in part from CO_2-emitting generation, meaning that while CO_2 emissions from the Company's fleet would be near zero, regional CO_2 emissions would remain at similar levels as Plan B.

- Plan D – This Alternative Plan uses similar assumptions as Plan C but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan D significantly increases the amount of solar resources needed to reach zero CO_2 emissions in 2045. Specifically, over the Study Period, this Plan includes approximately 9.2 GW of incremental solar capacity and approximately 4.8 GW of incremental energy storage as compared to Plan B, which is approximately 8.1 GW more solar capacity than Plan C. Like Plan C, beginning in Year 16 of Plan D, the Company's transmission import capacity would need to be doubled to approximately 10.4 GW total in order to support the Company's winter import needs, as well as spring and fall export needs. Accordingly, also like Plan C, regional CO_2 emissions would remain at similar levels as Plan B based on the increased dependence on imported power. Notably, the lower 19% capacity factor is based on the historical performance of the Company's solar generation resources as required by an SCC order; in the Company's view, this 19% capacity factor does not represent a reasonable estimate of solar generation's expected potential.

The following table presents a high-level summary of the Alternative Plans:

Executive Summary Table: 2020 Plan Results

	Plan A	Plan B	Plan C	Plan D
NPV Total ($B)	$44.3	$66.2	$78.6	$80.8
Approximate CO_2 Emissions from Company in 2045 (Tons)	24 M	10 M	0	0
Approximate CO_2 Emissions Regionally in 2045 (Tons)	34 M	4 M	4 M	5 M
Solar (MW)	6,720 15-year 11,520 25-year	15,920 15-year 31,400 25-year	15,920 15-year 32,480 25-year	18,800 15-year 40,640 25-year
Offshore Wind (MW)	--- 15-year --- 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year
Storage (MW)	--- 15-year --- 25-year	2,714 15-year 5,114 25-year	2,714 15-year 9,914 25-year	2,714 15-year 9,914 25-year
Natural Gas-Fired (MW)	1,940 15-year 3,531 25-year	970 15-year 970 25-year	970 15-year 970 25-year	970 15-year 970 25-year
Import / Export Capability (MW)	5,200 15-year 5,200 25-year	5,200 15-year 5,200 25-year	5,200 15-year 10,400 25-year	5,200 15-year 10,400 25-year
Retirements (MW)	3,030 15-year 4,651 25-year	3,183 15-year 5,414 25-year	3,183 15-year 13,978 25-year	3,183 15-year 13,978 25-year

As can be seen in the table above, Alternative Plans B through D are very similar over the first 15 years. This general alignment over the Planning Period sets a common pathway for the Company to pursue now while allowing new technologies to mature. All Alternative Plans include 970 MW of natural gas-fired combustion turbines ("CTs") as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities. While all Alternative Plans in this 2020 Plan incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Study Period. The Company intends to explore all new and promising technologies that support a cleaner future and that will enable the Company to achieve its environmental goals, as well as the goals of Virginia and North Carolina. The Company will provide information on these developments in future Plans and update filings.

Based on the current state of technology and the need for technological advances to truly achieve a cleaner future, Alternative Plans B through D as presented in this 2020 Plan all pose challenges over the long term.

Alternative Plans B through D factor in the implementation of energy efficiency programs and measures to achieve both 5% total annual energy savings by 2025, as targeted by the VCEA, and $870 million in proposed spending by 2028, as required by the Grid Transformation and Security Act of 2018 (the "GTSA"). The Company has modeled these objectives by supplementing the Company's approved and pending DSM programs with a generic level of energy efficiency at a fixed price. This approach is a theoretical assumption used for planning purposes only. In reality, the level of energy efficiency savings included in this 2020 Plan may not materialize in the same manner as modeled due to many outside factors. These factors include the ability of future vendors to deliver program savings at the assumed fixed price, the desire of customers to participate in the program at that price, and the effectiveness of the program to be administered at that price. The modeled costs and level of savings attributable to generic energy efficiency are thus placeholders as future phases of actual energy efficiency programs are developed and implemented.

From a permitting perspective, all Alternative Plans include large quantities of solar capacity located in Virginia. In fact, to meet customers' demand, Alternative Plans B through D require between 31,400 MW and 40,640 MW of new solar capacity by 2045. Given current technology, 31,400 MW of solar generating capacity in the Commonwealth would require the land use of 490 square miles. This land mass is nearly 25% larger than Fairfax County, Virginia, or the equivalent of nearly 237,000 football fields. Utilization of such a large land mass area for energy generation will likely encounter local and environmental permitting issues.

The large quantities of solar capacity in Alternative Plans B through D also pose challenges from a technical perspective. A key component included in the traditional design of the North American electric power grid is the inertia from many existing traditional turbines to create a reservoir of kinetic energy. This kinetic energy automatically provides grid support by balancing the myriad of instantaneous discrepancies between generation and load at any moment in time. Inverter-based generation such as intermittent solar and wind resources do not provide such a reservoir of kinetic energy. Therefore, the retirement of traditional generation units coupled with the addition of large quantities of intermittent renewable generation will adversely affect both electric system reliability and the Company's ability to restore the system in the event of a large-scale blackout. Transmission planning work has begun, but more planning analysis is necessary to model the grid under different conditions to assure system reliability, stability, and security with the retirement of traditional generation. Although Plans B through D show significantly reduced carbon emissions by 2045 associated with these projected retirements, additional transmission and distribution projects potentially needed to address system reliability and security have not been fully assessed and evaluated in this 2020 Plan. The Company will provide the results of these additional analyses in future Plans and update filings.

In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

In Alternative Plan B, the Company preserved approximately 9,700 MW of efficient natural gas-fired generation units to address these future system reliability, stability, and energy independence issues. In future Plans, these units could be replaced by new types of generation such as small modular reactors. These units could also be transformed into low-carbon or carbon-free generation by installing new technologies such as carbon capture sequestration or refueling these units with hydrogen or renewable natural gas. For example, the Company could use excess energy from renewable facilities during periods of lower demand (*i.e.*, spring and fall) to create and store hydrogen fuel that could subsequently be used in these gas-fired generators. When hydrogen fuel is used in gas-fired generators, the byproduct is water rather than CO_2. The Company will continue to study these types of innovative alternatives and will, when and if feasible, reflect those alternatives in future Plans.

Unlike Alternative Plan B, Alternative Plans C and D model the retirement of all Company-owned carbon-emitting generation by 2045. If the Company retires all carbon-emitting generation units by 2045 as modeled in Alternative Plans C and D, given current energy storage and solar technology—and even with approximately 10,000 MW of new incremental storage—customers' winter peak load demand could not be met unless grid transmission import capacity is approximately doubled. Doubling transmission import capacity is a significant task that requires additional study, and would require significant capital expenditures and permitting challenges. Even if this import capacity could be doubled from a technical perspective, Virginia would become dependent on other jurisdictions to meet its winter peak needs, which, in the Company's view, presents an unacceptable risk. This risk increases as neighboring states elect to pursue the development of significant solar resources similar to Virginia and face similar challenges meeting winter peak load demand. Doubling transmission import capacity as modeled in Plans C and D would also result in similar regional CO_2 emissions as Alternative Plan B because the imported power from PJM would come in part from CO_2-emitting generation.

Separate from the proposed build plans and related system upgrades, Alternative Plans B through D include foundational investments to transform the Company's electric distribution grid to facilitate the integration of DERs, to enhance reliability and security, and to improve the customer experience (the "Grid Transformation Plan"). The Grid Transformation Plan will prepare the Company's distribution grid to support the cleaner future envisioned by Virginia, North Carolina, and the Company. For example, with advanced metering infrastructure ("AMI") and a new customer information platform, the Company can offer advanced rate options to all customers across its system targeted at energy efficiency and demand reduction. A transformed grid will also support electric vehicle ("EV") adoption while minimizing the effect of EV charging on the distribution grid, thus maximizing the benefits of electrification. Foundational components of the Grid Transformation Plan, such as AMI, deployment of intelligent grid devices, advanced control systems, and a robust and secure telecommunications network, are necessary to integrated distribution planning that can produce inputs into future Plans.

The Company fully supports the transition towards clean energy without compromising reliability, and stands ready to meet the challenges discussed with continued study, technological advancement, and innovation. Importantly, as noted above, the first 15 years of Alternative Plans B through D present very similar paths forward; the dramatic differences between the Alternative Plans occur during the last ten years of the 25-year Study Period. This alignment between Alternative Plans B through D over the 15-year Planning Period creates a common pathway for the Company to pursue now while allowing new technologies to emerge and mature, and allowing analysis and study to continue. Accordingly, for this 2020 Plan, the Company recommends a path forward that substantially aligns with the first 15 years of Alternative Plans

B through D. Over the longer-term, however, based on current technology and this "snapshot in time," the Company recommends Alternative Plan B.

Going forward, long-term integrated resource plans will evolve and will continue to support the cleaner future envisioned by public policy, by lawmakers, and by the Company. As noted, this future, while achievable, will require supportive legislative and regulatory policies, technological advancements, and broader investments across the economy. It will also require further study and analyses of necessary investments in the transmission and distribution systems to ensure the reliable electric service that customers expect and deserve. Overall, the Company's deliberate transitional approach to a cleaner future has, and will continue, to provide customers a path to clean energy that meets public policy objectives while maintaining the standard of reliability necessary to power Virginia's and North Carolina's modern economies.

Chapter 1: Significant Developments and Context for Integrated Planning Process

The Company's comprehensive planning process considers significant emerging policy, market, regulatory, and technical developments that could affect its operations and, in turn, its customers.

1.1 Dominion Energy Net Zero Target

In February 2020, Dominion Energy announced its commitment to net zero CO_2 and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050. The goal covers CO_2 and methane emissions, the dominant greenhouse gases ("GHGs"), from electricity generation and gas infrastructure operations. The strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions.

Net zero is a framework under which companies effectively achieve "zero" emissions through a combination of actions to reduce emissions at their own facilities and through initiatives such as reforestation and various other verifiable measures that reduce emissions. By 2050, Dominion Energy is committed to achieve net zero CO_2 and methane emissions across all of its electric and natural gas operations in all 20 states where it does business, which is the timeframe referenced in climate work published by the United Nations Intergovernmental Panel on Climate Change. Dominion Energy has been actively lowering its CO_2 and methane emissions by employing existing technology and resources, such as extending the licenses of its zero-carbon nuclear fleet; rapidly expanding wind and solar resources; continuing to rely on low-carbon natural gas; promoting the use of electric vehicles and energy efficiency; and investing in renewable natural gas. Dominion Energy continuously monitors internal operations and external factors (*e.g.*, technology, public policy, stakeholder feedback) to assess for appropriateness in all of its sustainability commitments, including its climate goals.

Achieving net zero CO_2 and methane emissions will require technological advancements in the utility sector and broader investments in technology across the entire economy in the long term. In the near term, Dominion Energy will continue to explore new technologies to accelerate future progress. This includes an industry-leading methane emissions reduction program that is one of the most aggressive and sweeping in the nation. Dominion Energy has reduced methane emissions from its gas infrastructure by approximately 25% since 2010 and has committed to achieving a 65% reduction by 2030 and an 80% reduction by 2040. In addition, Dominion Energy has partnered with the nation's largest hog and dairy producers to turn farm waste into clean renewable natural gas. By 2029, these projects will reduce methane emissions from the nation's farms by the same amount as taking 650,000 cars off the road or planting 50 million new trees each year. Overall, Dominion Energy is committed to pursuing all reasonable paths to assure its goal of net zero CO_2 and methane emissions is achieved while maintaining the reliability that customers demand.

1.2 Virginia Clean Economy Act

The VCEA—Senate Bill No. 851 and House Bill No. 1526 from the 2020 Regular Session of the Virginia General Assembly—was signed into law on April 11, 2020, and becomes effective July

1, 2020. The VCEA includes provisions that institute a mandatory renewable portfolio standard, enhance renewable generation and energy storage development, require the retirement of certain generation units, establish energy efficiency targets, and expand net metering.

- The VCEA establishes a mandatory RPS that:
    - Includes RPS annual requirements based on a percentage of non-nuclear electric energy sold by the Company, reaching 100% by 2045;
    - Sets standards for meeting the RPS requirements, including 1% from distributed generation and 75% from resources located in the Commonwealth;
    - Requires the development of renewable generation and energy storage resources, as discussed further below;
    - Requires the retirement of generation units that emit CO_2 as a byproduct of combustion, as discussed further below;
    - Recognizes the benefits and necessity of nuclear license extensions; and
    - Establishes penalties if the Company does not meet the RPS requirements in any compliance year.

- The VCEA requires the Company to petition the SCC for approval to construct or purchase up to 5,200 MW of offshore wind generation and declares such offshore wind generation to be in the public interest if those facilities achieve commercial operation by 2034.
    - The costs associated with between 2,500 MW and 3,000 MW of utility-owned offshore wind are presumed to be reasonably and prudently incurred if the facilities achieve commercial operation by 2028, the Company complies with mandated competitive procurement requirements, and the levelized cost of energy ("LCOE") does not exceed 1.4 times the LCOE of a CT as estimated by the U.S. Energy Information Administration in 2019.

- The VCEA requires the Company to petition the SCC for approval to construct or purchase 16,100 MW of solar or onshore wind generation located in the Commonwealth.
    - The Company must petition for approval to construct or purchase the 16,100 MW of solar or onshore wind generation on the following schedule:
        - 3,000 MW by 2024;
        - 6,000 MW by 2027;
        - 10,000 MW by 2030; and
        - 16,100 MW by 2035.
    - Thirty-five percent of the solar and onshore wind generating capacity must be procured from third-party-owned facilities through power purchase agreements ("PPAs").
    - The 16,100 MW development must include 1,100 MW of small-scale solar (*i.e.*, projects less than 3 MW), and 200 MW of solar placed on previously developed project sites.

- The VCEA requires the Company to petition the SCC for approval to construct or purchase 2,700 MW of energy storage resources located in the Commonwealth and declares such resources to be in the public interest provided those facilities achieve commercial operation by 2035.

- At least 35% of such energy storage capacity must be procured from third-party-owned resources through PPAs.
- Ideally, at least 10% of energy storage resources should be located behind the meter.
- The Company may procure a single energy storage project up to 800 MW, allowing for construction of a pumped hydroelectric storage facility.

- The VCEA mandates the retirement of generation units that emit CO_2 as a byproduct of combustion on the following schedule, unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric service:
    - Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024;
    - Altavista, Hopewell, and Southampton (biomass) by 2028; and
    - All remaining generation units that emit CO_2 as a byproduct of combustion by 2045.

- The VCEA encourages energy efficiency programs and measures that target a 5% reduction in energy sales (as measured against 2019 jurisdictional electricity sales) by 2025.
    - The SCC would evaluate the programs in 2025 and establish the going-forward savings targets in three year increments.
    - If targets are not achieved, costs of energy efficiency programs would be recovered without a margin, and the SCC may not certificate new generation units that emit CO_2 as a byproduct of combustion unless a threat to system reliability or security exists.

- The VCEA expands the net metering cap from 1% to 6% of the previous year's adjusted peak load forecast, with 1% reserved for low-income customers.
    - At the earlier of 2025 or after 3% of the previous year's peak demand is reached, the SCC will initiate a proceeding to determine a new net metering rate.

The VCEA formalizes the administrative policy goals set by Virginia Governor Northam in September 2019 through Executive Order 43: Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future ("EO43"). EO43 established statewide goals and targets for reducing carbon emissions. Specifically, EO43 included a goal that by 2030, 30% of the Commonwealth's electric system would be powered by renewable energy sources. By 2050, the goal was for 100% of Virginia's electricity to be produced from carbon-free sources such as wind, solar, and nuclear. In establishing a mandatory RPS, the VCEA sets forth a framework to meet the goals of EO43.

1.3 Regional Greenhouse Gas Initiative

RGGI is a collaborative effort to cap and reduce CO_2 emissions from the power sectors of participating states, which currently include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

The concept of Virginia joining RGGI is not new. Starting with former Governor McAuliffe's Executive Directive 11, Virginia began a process that has thoroughly investigated RGGI and the effect of Virginia's participation. On May 27, 2019, the Virginia Department of Environmental Quality ("VDEQ") published a final rule that established a state cap-and-trade program for electric generation units ("EGUs") in Virginia (the "VDEQ Carbon Rule"). The VDEQ Carbon Rule became effective on June 26, 2019.

In 2019, the state budget bill (signed by Virginia Governor Northam) prohibited VDEQ from continued work on the VDEQ Carbon Rule. The VDEQ Carbon Rule thus included a section that allowed for delayed implementation. Specifically, implementation of most elements of the program, including requirements for holding and surrendering CO_2 allowances, was delayed until further authorization for appropriating funding to implement the program. Nevertheless, the VDEQ Carbon Rule included specific near-term requirements for affected entities, including:

- A requirement to submit to the VDEQ by August 25, 2019, the annual net electric output in megawatt-hours ("MWh") for calendar years 2016, 2017, and 2018 for each EGU subject to the rule, which the VDEQ would use to determine the CO_2 allowance allocations for the initial control period; and

- A requirement to submit to the VDEQ by January 1, 2020, a complete CO_2 budget permit application for affected sources with an applicable EGU subject to the program.

The Company complied with these requirements by the required deadlines. While the final VDEQ Carbon Rule removed specific references to RGGI, the rule remained structured in a way that would allow for the Virginia program to link with a regional program such as RGGI.

Other key elements of the VDEQ Carbon Rule as finalized are:

- A starting (baseline) statewide CO_2 emissions cap of 28 million tons in 2020, reduced by about 3% per year through 2030, resulting in a 2030 cap of 19.6 million tons (however, the rule allowed for adjustment of the starting cap for delayed implementation);

- No references to continued cap reductions after 2030 that the VDEQ had included in prior versions of the rule;

- Reinstated language to clarify that affected units under the rule would only have to hold allowances for emissions associated with fossil fuel combustion, assuring that the Company's Virginia City Hybrid Energy Center ("VCHEC") would not have to hold allowances for emissions related to biomass co-firing; and

- No opportunity to generate offsets from projects in Virginia, though the rule includes a provision that would recognize eligible emissions offsets from other participating states in a regional trading program. The VDEQ has indicated it may re-evaluate offset provisions during the next program review.

In 2020, legislation passed the Virginia General Assembly related to RGGI. In addition to the legislative provisions of the VCEA discussed in Section 1.2, the VCEA also directs Virginia's participation in a carbon trading program through 2050. Separate legislation provides for Virginia's participation in RGGI. Specifically, the Clean Energy and Community Flood Preparedness Act—Senate Bill No. 1027 and House Bill No. 981 from the 2020 Regular Session of the Virginia General Assembly—will become law effective July 1, 2020. This Act authorizes Virginia to join RGGI directly and authorizes the VDEQ to implement the VDEQ Carbon Rule. Given the passage of this Act combined with Virginia's previous efforts associated with RGGI participation, the Company believes it is highly probable that Virginia will become a full RGGI participant.

1.4 North Carolina Clean Energy Plan

In October 2018, North Carolina Governor Cooper issued Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy ("EO80"). Among other goals, EO80 set a statewide GHG reduction goal of 40% by 2025 (using a 2005 baseline), an electric power sector goal of 70% GHG reduction by 2030 (using a 2005 baseline), and a carbon neutrality goal by 2050. EO80 also required the North Carolina Department of Environmental Quality ("NCDEQ") to develop a North Carolina Clean Energy Plan to establish pathways for achieving the EO80 goals. After the public comment period, NCDEQ issued the final North Carolina Clean Energy Plan in October 2019. NCDEQ has also established stakeholder groups to establish recommendations for policy designs to align with EO80 goals.

1.5 Need for a Modern Distribution Grid

Electricity has become a basic need, vital to the economy, to public safety, and to customers' way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, large medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pumping facilities. As society has grown more dependent on electricity, customers expect both highly reliable service and easy access to their energy usage information so that they can make informed decisions about their consumption. Another fundamental change in the energy industry is the emerging shift within the transportation industry as it continues toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. Even a brief interruption or power quality anomaly at, for example, a data center can be catastrophic for both the data center itself and the businesses that rely on that data center. While service interruptions have always been an inconvenience in modern society, the safe, reliable, and consistent delivery of power has never been more important than it is today.

In addition to the increasing importance of reliable electric service, the rise of DERs requires a fundamental change to the electric grid. With DERs, electricity is now flowing onto the distribution system from multiple points. The distribution system that was designed for the one-way flow of electricity must now accommodate the two-way flow of electricity. In addition, the intermittent nature of some of these DERs resulting from weather variability creates power fluctuations not typical of traditional generation resources. Propagated in an arbitrary manner, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility on and control of the distribution system, DERs can transform into a system resource that can be equitably managed to maximize the value of other available resources, and potentially offset the need for future "traditional" generating assets or grid upgrades, all while maintaining reliable service to customers.

Because DERs rely on the distribution system to deliver the electricity they produce, a resilient distribution system is vital to maximizing the value of DERs. Day to day outages, as well as major weather events, not only cause prolonged outages for customers, but also prevent DERs from delivering electricity. The distribution system must be reliable and resilient so that it can operate for DERs like the transmission system operates for large, centralized generators.

Foundational investments to transform the distribution grid will allow the Company to use the distribution system differently than it does today, all for the benefit of customers. Transformational investments in infrastructure resilience, AMI, a customer information platform, intelligent grid devices, automated control systems, and advanced analytics will enable the Company to improve operations (*e.g.*, more efficient restoration, reducing truck rolls, more predictive and efficient maintenance, and increased visibility), better forecast load shape, and better predict future behaviors (*e.g.*, identifying and fixing grid problems before an outage occurs), resulting in a better, more informed customer experience that meets customers' changings needs and expectations.

1.6 Forward Capacity Markets

The Company is closely following the developments in the PJM forward capacity market, including the Federal Energy Regulatory Commission ("FERC") Minimum Offer Price Rule ("MOPR") proceedings, and is considering its options, including election of the fixed resource requirement ("FRR") alternative. As discussed further in Section 4.2, however, the modeling for this 2020 Plan is indifferent to whether the Company participates in the PJM forward capacity market or elects the FRR alternative.

1.6.1 Minimum Offer Price Rule

PJM has had the MOPR concept in place since the late 2000s. MOPR is designed to prevent price suppressive behavior of resources that participate in PJM's Reliability Pricing Model ("RPM") capacity market. This rule requires new resources to bid into the capacity market at or above the resource type's net cost of new entry ("Net CONE"). CONE reflects a resource's capital investments and fixed operations and maintenance ("O&M") expenses. Net CONE refers to CONE value net of the expected energy and ancillary market revenues. Net CONE, therefore, reflects the capacity revenue the resource would need to remain profitable.

Some generation entities filed a complaint at FERC in 2017 arguing the lack of effectiveness of capacity markets in PJM due to state subsidies. Specifically, the generation entities argued that state subsidies could have the effect of lowering capacity market clearing prices because the units receiving subsidies were receiving additional revenue that lowered their need from the market.

On June 29, 2018, FERC issued an order finding that PJM's Open Access Transmission Tariff was unjust and unreasonable because the MOPR "fail[ed] to address the price-distorting impact of resources receiving out-of-market support" (the "FERC MOPR Order"). On December 19, 2019, FERC directed PJM to expand MOPR to address state-subsidized resources, with very limited exemptions. Although one of the exemptions included existing self-supply resources, the FERC MOPR Order would subject new resources from self-supply entities (such as the Company) to the expanded MOPR. Because there is no guarantee that the capacity market would clear above a resource's Net CONE value (which it never has), the capacity market revenues for most new resources, including those from self-supply entities, would be uncertain.

On March 19, 2020, PJM submitted its compliance filing on the FERC MOPR Order. Specifically, PJM's compliance filing sets the Net CONE and net avoidable cost rate values for necessary resource classes; offers flexibility for unit-specific offer reviews; addresses circumstances where resources elect the competitive exemption and receive a subsidy later; and establishes auction timing for the 2022/2023 delivery year and beyond.

1.6.2 Fixed Resource Requirement Alternative

The Company joined PJM in 2005. In 2007, in order to assure reliability, PJM instituted the RPM, which created a forward generation capacity market that placed a value on reliability. PJM's existing rules allow vertically-integrated utilities to opt out of the capacity market by electing the FRR alternative. American Electric Power Company, the parent of Appalachian Power Company, has been the only significant utility in PJM to use this option since 2007.

The Company has participated in the RPM forward capacity market since 2007. One advantage of the RPM forward capacity market is that it draws upon resources from across PJM to ensure that sufficient supply- and demand-side resources are secured three years before they may be called upon to serve customer load. The market will pay those resources for their availability when the future delivery year arrives. This forward market provides a financial incentive and a degree of certainty designed to incentivize investment in new and existing resources beyond what is available through PJM's energy and ancillary services markets. The three-year forward auctions in the RPM have resulted in auction clearing reserve margins in the approximately 19% to 24% range—in excess of PJM's installed reserve margin—which means that the DOM LSE must purchase about 20% more unforced capacity than its forward load forecast. RPM participation considers a variable resource requirement defined by a demand curve in relation to supply offers; where supply offers cross the demand curve creates the capacity clearing price and the reserve margin for load. Based on the recent FERC MOPR Order, virtually all new generation resources will need to offer at Net CONE or an otherwise calculated market seller offer cap—which could be above the RPM market clearing price—resulting in $0 revenue for these un-cleared resources.

As an alternative to the RPM forward capacity market, PJM permits the FRR construct. The Company is eligible to elect the FRR alternative because it is an investor-owned utility. One of the key requirements for FRR is to demonstrate that sufficient generation resources are available to meet the reliability requirement for the FRR service area. The reliability requirement for the FRR service area is the forward load forecast plus the target reserve margin. This is one of the primary differences between RPM and FRR, as the PJM coincident peak target reserve margin for FRR is forecasted to be approximately 15%—over 5% less than where the RPM market has been clearing recently. From a long-term planning perspective, this reserve margin requirement difference could be significant. If the Company's forecasted load was 20,000 MW, for each percent difference between cleared reserve margin and target reserve margin, electing FRR would result in about a 200 MW reduction in purchase requirement. That said, considering the FERC MOPR Order and related filings, both the clearing price and the clearing reserve margin of the upcoming RPM forward capacity market remain highly uncertain.

An FRR election is for a minimum of five consecutive delivery years. A load serving entity ("LSE") must demonstrate its ability to meet the reserve requirement on an annual basis by committing sufficient resources to meet the reliability requirement as part its FRR plan. If an FRR plan's capacity commitment is insufficient for a delivery year, the LSE would be assessed an FRR commitment insufficiency charge for the shortage. This penalty is two times Net CONE times the MW deficiency. Capacity resources committed to an FRR plan continue to be subject to the same capacity performance requirements that apply to resources committed through the RPM forward capacity market if they are called upon in an emergency. To the extent an LSE has capacity in excess of its load requirement, those excess capacity resources may not generate the same revenue as if offered into the RPM market. The first 450 MW of excess capacity is held in reserve until the third incremental auction, with the next additional block of excess capacity up to 1,300 MW being able to offer into the RPM market auctions.

Because of its five-year minimum commitment requirement, risks to FRR election should be carefully weighed against the benefits. Risks include future environmental changes, regulatory changes, zonal constraints, and capacity and energy market changes. The potential benefits of FRR election include lower required reserve margin and the absence of MOPR risk to new generation used to meet the load obligation. All new generation would be able to be counted against the load obligation with the FRR alternative, whereas with RPM there is the likelihood that new generation would receive no capacity revenue to offset the load cost. If the Company opts out of the RPM forward capacity market through the election of the FRR alternative, it would continue to participate in PJM's energy and ancillary services markets in the same manner it does today.

The Company is continuing to evaluate the FERC MOPR Order and the FRR alternative; it has made no decision at this time. If the Company were to elect FRR, it would have to do so in advance of the next RPM base auction. Typically, this election would need to happen about six months prior to that auction; however due to the pending MOPR-related filings with FERC, the schedules may be compressed. The schedule depends on if, and when, FERC accepts PJM's recent compliance filing. PJM currently estimates the next RPM auction to occur in late 2020 or early 2021, depending on FERC's response to the PJM compliance filing.

1.7 Environmental Justice

Environmental justice is defined as the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. The Company is dedicated to meeting environmental justice expectations of fair treatment and meaningful involvement by being inclusive, understanding, and dedicated to finding solutions, and by effectively communicating with its customers and neighbors. The Company adopted an environmental justice policy in 2018 through which it committed to hearing, fully considering, and responding to the concerns of all stakeholders. This commitment includes ensuring that a voice in decisions about siting and operating energy infrastructure is given to all people and communities. Communities should have ready access to accurate information and a meaningful voice in the project development process. The Company has pledged to be a positive catalyst in its communities.

Environmental justice is also a priority for Virginia and North Carolina. In its 2020 Regular Session, the Virginia General Assembly passed multiple bills aimed at promoting environmental justice. This legislation, among other things, establishes the Virginia Council on Environmental Justice to advise the Governor on the advancement of environmental justice, and adds as a purpose of the VDEQ to further environmental justice. In addition, the Virginia Environmental Justice Act—Senate Bill No. 406 and House Bill No. 704 from the 2020 Regular Session of the Virginia General Assembly—establishes "the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth." Similarly, in North Carolina the Secretary of NCDEQ established an Environmental Justice and Equity Advisory Board to assist NCDEQ in achieving fair and equal treatment of all communities across the state. The Company is dedicated to meeting these environmental justice expectations.

1.8 New and Developing Technologies

Dominion Energy has assembled a new organization dedicated to pursuing innovative and sustainable technologies that will help guide the Company toward the clean future envisioned by Virginia and North Carolina. Some of the more promising new technologies being investigated are as follows:

- **Natural Gas Combined-Cycle Technology with Carbon Capture and Sequestration**. Natural gas combined-cycle plants fitted with carbon capture and sequestration ("CCS") are being consistently modeled as a necessary component of a low-carbon electric generation portfolio. Models of low-carbon scenarios by the Intergovernmental Panel on Climate Change, the International Energy Agency, Bloomberg New Energy Finance, and others all show significant contributions from CCS in the electric generation sector.

- **Hydrogen.** Hydrogen is both a fuel and a carrier that can be used to store and transport energy. Opportunities exist in the production, transportation, and usage of hydrogen to support a clean energy future when produced from low- or no-carbon sources. One example is the use of hydrogen to "co-fire" natural gas generation. Production and storage of hydrogen fuel can be one solution to the excess renewable energy that may result as increasing amounts of renewable generation resources are added to the grid.

- **Electric Vehicles as a Resource.** Electric vehicles are becoming more prolific in most forms of transportation. With EVs, new technologies and software are being developed to maximize the benefits of electrification, such as load shifting and other applications that complement renewable generation. For example, vehicle-to-grid ("V2G") technologies are being developed through which electricity stored in EVs' batteries can be fed back onto the grid to lower peak demand or to provide grid support. See Section 8.6 for a discussion of the Company's Electric School Bus Program through which it seeks to explore V2G technology. A precursor to take advantage of this resource is a modernized grid that has full situational awareness.

- **Renewable Natural Gas.** Renewable natural gas ("RNG") is derived from biomethane or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. RNG can thus be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, industrial applications, and transportation. Adding RNG as a source of natural gas generation reduces overall emissions. These sources may be expanded based on new technologies to capture RNG from untapped sources and in remote areas.

- **Continuous Improvement in Solar Output.** Solar technology improvements such as advanced trackers, bifacial modules, and other technologies continue to improve capacity, output, intermittency profiles, and operational efficiency of solar generation. As these technologies mature, these improvements—especially higher capacity factor improvements—could provide more carbon-free generation with potentially less land use.

- **Medium and Long-Term Energy Storage.** The need for energy storage will grow with the proliferation of intermittent generation. Storage technologies that are on the horizon include new and improved batteries, hydrogen, thermal storage, and mechanical storage. See Section 5.5.1 for additional discussion of energy storage technologies.

- **Carbon Offsets.** There is a substantial and growing market in carbon offsets in the United States. Carbon offsets can be generated by any activity that compensates for the emission of CO_2 or other GHGs (measured in carbon dioxide equivalents ("CO_2e")) by providing for an emission reduction elsewhere. Because greenhouse gases are widespread in Earth's atmosphere, there is a climate benefit from emission reductions regardless of where the reductions occur. If carbon reductions are equivalent to the total carbon footprint of an activity, then the activity is said to be "carbon neutral." Carbon offsets can be bought, sold, or traded as part of a carbon market. Carbon offsets, verified by third parties, are used in voluntary and compliance markets across the country.

- **Direct Air Capture Technology.** This aspirational technology is an industrial process for large-scale capture of atmospheric CO_2. Direct air capture ("DAC") technology pulls in atmospheric air then, through a series of chemical reactions, extracts the CO_2 from it while returning the rest of the air to the environment. This is what plants and trees do every day as they photosynthesize, except DAC technology does it much faster, with a smaller land footprint, and delivers the CO_2 in a pure, compressed form that can then be stored underground or reused. The potential of the DAC technology is tied to systems where excess or curtailed renewable energy is available at a very low cost to power the industrial process that removes CO_2 from the air. Utilizing the captured CO_2 to develop other products provides additional support to this process. Captured CO_2 can be produced in a solid form for safe storage creating a "negative emissions" industrial scale process, or can be paired with end-use applications such as oil field CO_2 recovery or development of synthetic fuels to provide carbon neutral transportation fuels.

- **The HAZER® Process.** The HAZER® Process converts natural gas into hydrogen and high quality graphite using iron ore as a process catalyst. The aim of the HAZER® Process is to achieve savings for the hydrogen producer, as well as providing "clean" hydrogen with significantly lower CO_2 emissions. This "clean" hydrogen can then be used in a range of developing clean energy applications, including power generation. The graphite can be used in the production of lithium ion batteries.

- **Advanced Analytics.** The economy is experiencing both a rapid increase in computing power and an explosive growth in data. Both trends will allow energy companies to manage the electric grid and aggregate resources in ways that they have not been able to do in the past, providing additional opportunities to reduce CO_2 emissions. A precursor to the use of this data is a modernized grid that gathers data through AMI and intelligent grid devices, and incorporates a sophisticated distributed energy resource management system.

1.9 COVID-19

At the time of filing this 2020 Plan, the world continues to confront the ongoing public health emergency related to the spread of coronavirus, also known as COVID-19. The Company's first priority is the health, safety, and well-being of its employees and communities. For its employees, the Company implemented early directives limiting travel, instituting work-from-home protocols, and expanding health and paid-time-off benefits. For its customers, the Company has suspended service disconnections for all customers, waived late payment fees for all customers, and worked to reconnect certain residential customers.

Because of the preparation schedule associated with this 2020 Plan, the Plan does not reflect any potential effects related to the COVID-19 public health emergency. PJM has published initial reports of lower demand for electricity. The Company believes it is too early to predict the long-term effects of the COVID-19 public health emergency, including the effect on customer load. The Company will continue to monitor the effects of this ongoing public health emergency and will incorporate any long-term effects as needed in future Plans and update filings.

1.10 Other Legislative Developments

In addition to the VCEA and the legislation enabling Virginia to join RGGI discussed in Sections 1.2 and 1.3, respectively, legislation was signed into law on April 11, 2020, that incorporated the relevant policy objectives into the Virginia Energy Plan—Senate Bill No. 94 and House Bill No. 714 from the 2020 Regular Session of the Virginia General Assembly. Also relevant to this 2020 Plan, House Bill 889 established a pilot program for up to 200 MW of non-residential customers load to aggregate and purchase electricity from third-party suppliers. The Company has incorporated the effects of House Bill 889 into its load forecast, as discussed in Section 4.1.4.

1.11 Other Environmental Regulations

The following section outlines changes to various environmental regulations since the Company filed its 2018 Plan. The 2018 Plan contains a historical perspective on some of the environmental regulations discussed. For a comprehensive list of relevant environmental regulations, see Section 5.2.3.

1.11.1 Affordable Clean Energy Rule

The Environmental Protection Agency ("EPA") released the final version of the Affordable Clean Energy Rule ("ACE Rule") on June 19, 2019, which replaced and repealed the Clean Power Plan. The ACE Rule was published on July 8, 2019, and applies to existing coal-fired power plants greater than or equal to 25 MW.

Under the ACE Rule, the EPA has set the best system of emissions reduction ("BSER") for existing coal-fired steam EGUs as heat rate efficiency improvements based on a range of "candidate technologies" and improved O&M practices that can be applied at the unit level. States are directed to determine which of the candidate technologies apply to each covered EGU and establish standards of performance (expressed as an emissions rate in CO_2 pounds per MWh) based on the degree of emission reduction achievable with the application of BSER. The EPA required that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors such as reasonable cost of the candidate technologies. The ACE Rule requires compliance at the unit level; it does not allow averaging across units at the same facility or between facilities as a compliance option. In addition, it does not allow states to use alternative carbon mitigation programs, such as a cap-and-trade program, to demonstrate compliance as part of their state plans. A steam generating unit that is subject to a federally-enforceable permit that limits annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less, can be excluded from the ACE Rule.

The ACE Rule requires states to develop plans by July 2022. The EPA must approve these state plans by January 2024. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

1.11.2 New Source Performance Standards for Greenhouse Gas Emissions from Electric Generating Units

The EPA issued final Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units in October 2015. In December 2018, the EPA proposed revisions to these standards that have not yet been finalized. If finalized, these standards would apply to any newly constructed or reconstructed steam generating units or stationary CTs that (i) have a base load rating over 250 million British thermal unit ("MMBtu") per hour of heat input of fossil fuel and (ii) serve a generator capable of selling greater than 25 MW of electricity to a utility power distribution system. In the proposed revisions, the EPA did not revise the performance standard for newly constructed or reconstructed natural gas combined-cycle units, which remains at the 1,000 pounds CO_2 per gross MWh standard on a 12-operating month rolling average basis. Any newly constructed or reconstructed gas turbine selling greater than 25 MW of electricity to a utility power distribution system would need to comply with the CO_2 emission standards and work practice standards required by this rule.

1.11.3 Ozone National Ambient Air Quality Standards

The ozone National Ambient Air Quality Standard ("NAAQS") governs nitrogen oxide ("NO_x") emissions. The Company has entered into a mutual shutdown agreement with VDEQ to shut down and retire Possum Point Unit 5 by June 1, 2021, because the installation and operation of selective non-catalytic reduction technology to control NO_x emissions from that unit would otherwise be needed to meet reasonably available control technology ("RACT") requirements under the 2008 ozone NAAQS of 75 parts per billion ("ppb").

The Clean Air Act ("CAA") requires the EPA to review the NAAQS every five years and revise the NAAQS if necessary. On November 22, 2019, the EPA issued a finding that seven states including Virginia failed to submit state implementation plans to satisfy the interstate report requirements of the CAA as it pertains to the 2015 eight-hour ozone NAAQS. VDEQ submitted a draft proposal to the EPA for review in early February, and is awaiting a response from the EPA prior to the VDEQ opening its draft proposal for public comment.

The EPA initiated its review of the ozone NAAQS in May 2018 and concluded in a draft policy assessment that the current NAAQS of 70 ppb is adequate. The EPA expects to finalize this policy assessment, and issue a final decision in late 2020 or early 2021.

1.11.4 Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule ("CSAPR") aims to reduce emissions of sulfur dioxide ("SO_2") and NO_x from power stations in the eastern half of the U.S. CSAPR requires certain states to reduce annual SO_2 emissions and annual ozone season NO_x emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for SO_2 and NO_x and limits the trading for emission allowances by separating affected states into two groups with no trading allowed between the groups.

While CSAPR was originally intended to help downwind states attain the 1997 ozone NAAQS, the EPA revised the emission caps downward as an update to the CSAPR in 2016 in order to aid states in meeting the 2008 ozone NAAQS (the "CSAPR Update Rule"). As a companion to the CSAPR Update Rule, the EPA issued a rule in 2018 that found that states in the program need take no additional steps to meet the 2008 ozone NAAQS beyond compliance with the existing trading program's mandates (the "CSAPR Close-Out Rule").

On September 13, 2019, the D.C. Circuit partially remanded the CSAPR Update Rule to the EPA without vacating it. The court found that the rule was inconsistent with the CAA because it did not set a deadline by which upwind states must eliminate their significant contribution to downwind states' nonattainment of the 2008 ozone NAAQS to comply with the "good neighbor" provision of the CAA. On October 1, 2019, the D.C. Circuit granted consolidated petitions for review of the CSAPR Close-Out Rule, thereby vacating and remanding the rule back to the EPA.

1.11.5 New York's Clean Air Act Section 126(b) Petition

In March 2018, the State of New York filed a petition with the EPA under Section 126 of the CAA alleging that certain stationary sources of NO_x emissions in nine states—including several EGUs in Virginia that are owned and operated by the Company—contribute to nonattainment in New York and are interfering with maintenance of the 2008 or 2015 ozone NAAQS in New York. The petition requested the EPA to impose strict NO_x limits equivalent to RACT requirements that New York has imposed on its facilities. On October 18, 2019, the EPA finalized its decision to deny the petition on the basis that New York had not demonstrated (i) that any areas in New York except for one would exceed either the 2008 or 2015 ozone NAAQS by 2023, or (ii) that the identified sources contributed to any such exceedance. On October 29, 2019, New York, New Jersey, and New York City jointly filed a petition for review in the D.C. Circuit, challenging the EPA's denial of this petition. The Company is participating as an intervenor in the litigation in support of the EPA.

On February 19, 2020, the States of New Jersey, Connecticut, Delaware, New York, and Massachusetts, along with the City of New York filed a lawsuit against the EPA in the U.S. District Court for the Southern District of New York seeking to compel the EPA to promulgate federal implementation plans for the 2008 NAAQS for ozone that fully address the requirements of the "good neighbor provision" of the CAA for seven upwind states, including Virginia.

1.11.6 Mercury & Air Toxics Standards

In February 2019, the EPA published a proposed rule to reverse its previous finding that it is appropriate and necessary to regulate toxic emissions from power plants. However, the emissions standards and other requirements of the Mercury & Air Toxics Standards ("MATS") rule would remain in place, as the EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under MATS. All of the Company's applicable units are complying with the applicable requirements of the MATS rule.

On April 16, 2020, the EPA finalized its reconsideration of its MATS supplemental cost finding and its proposed residual risk and technology review for MATS. The action was consistent with the EPA's February 2019 proposal, and rescinded the supplemental finding that had found it appropriate and necessary for the EPA to regulate mercury and hazardous air pollutant emissions from power plants. The EPA concluded that it was not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under the MATS rule because the costs outweigh the benefits of emissions reductions. The EPA is also finalizing its determination that it will not be changing emissions standards for affected coal- and oil-based electric generating units. The effective date of the action will be 60 days after publication in the Federal Register. The Company expects that this action will result in litigation.

1.11.7 Coal Combustion Residuals

The Company currently operates inactive ash ponds, existing ash ponds, and coal combustion residual ("CCR") landfills at eight different facilities. In April 2015, the EPA enacted a final rule regulating (i) CCR landfills; (ii) existing ash ponds that still receive and manage CCRs; and (iii) inactive ash ponds that do not receive, but still store, CCRs. This rule created a legal obligation for the Company to retrofit or close all inactive and existing ash ponds over a certain period of time, and to perform required monitoring, corrective action, and post-closure care activities as necessary. Since the rule was enacted, the EPA has reconsidered portions of the rule in response to litigation and petitions for reconsideration. In July 2018, the EPA promulgated the first phase of changes to the CCR rule and continues to issue changes to the CCR rule. In August 2018, the D.C. Circuit issued a decision in the pending challenges of the CCR rule, vacating and remanding to the EPA three provisions of the CCR rule. The Company does not expect the scope of the D.C. Circuit's decision to affect its closure plans.

At the state level, in April 2018, Virginia Governor Northam signed legislation that required the Company to solicit and compile information from third parties on the suitability, cost, and market demand for beneficiation (*i.e.*, treatment of raw materials to improve chemical or physical properties) or recycling of coal ash from units at Bremo, Chesapeake, Chesterfield, and Possum Point. The coal ash recycling business plan was submitted to the Virginia General Assembly in November 2018. In March 2019, Governor Northam then signed legislation that required any CCR unit located at the Company's Bremo, Chesapeake, Chesterfield, or Possum Point power stations that stopped accepting CCR prior to July 2019 be closed by removing the CCR to an approved landfill or through recycling for beneficial reuse. The legislation further required that at least 6.8 million cubic yards of CCR be beneficially reused.

1.11.8 Clean Water Act

The Clean Water Act ("CWA") is a comprehensive program that uses a broad range of regulatory tools to protect the waters of the United States, including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms.

Section 316(b)

In October 2014, the final regulations under Section 316(b) of the CWA became effective; these regulations govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day ("MGD"), with a heightened entrainment analysis for those facilities over 125 MGD.

The Company currently has seven facilities that are subject to the final Section 316(b) regulations. Additionally, the Company may have one hydroelectric power facility subject to the final regulations. The Company anticipates that it may have to install impingement control technologies at certain of these stations that have once-through cooling systems. The Company is currently evaluating the need or potential for entrainment controls under the final rule; decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost, and benefit studies.

Effluent Limitation Guidelines

In September 2015, the EPA revised its effluent limitations guidelines ("ELG") for the steam electric power generating category. The final rule established updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required (i) to convert from wet to dry or closed cycle coal ash management, (ii) to improve existing wastewater treatment systems, and/or (iii) to install new wastewater treatment technologies in order to meet the new discharge limits. In April 2017, the EPA granted two separate petitions for reconsideration of the ELG rule and stayed future compliance dates in the rule. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the ELG rule from November 2018 to November 2020; however, the latest date for compliance for these regulations remains December 2023.

In November 2019, the EPA released proposed revisions to the ELG rule that, if adopted, could extend the deadlines for compliance with certain standards at several facilities. The effects of this revised rule are still being evaluated and studies are currently underway to determine the best path for compliance.

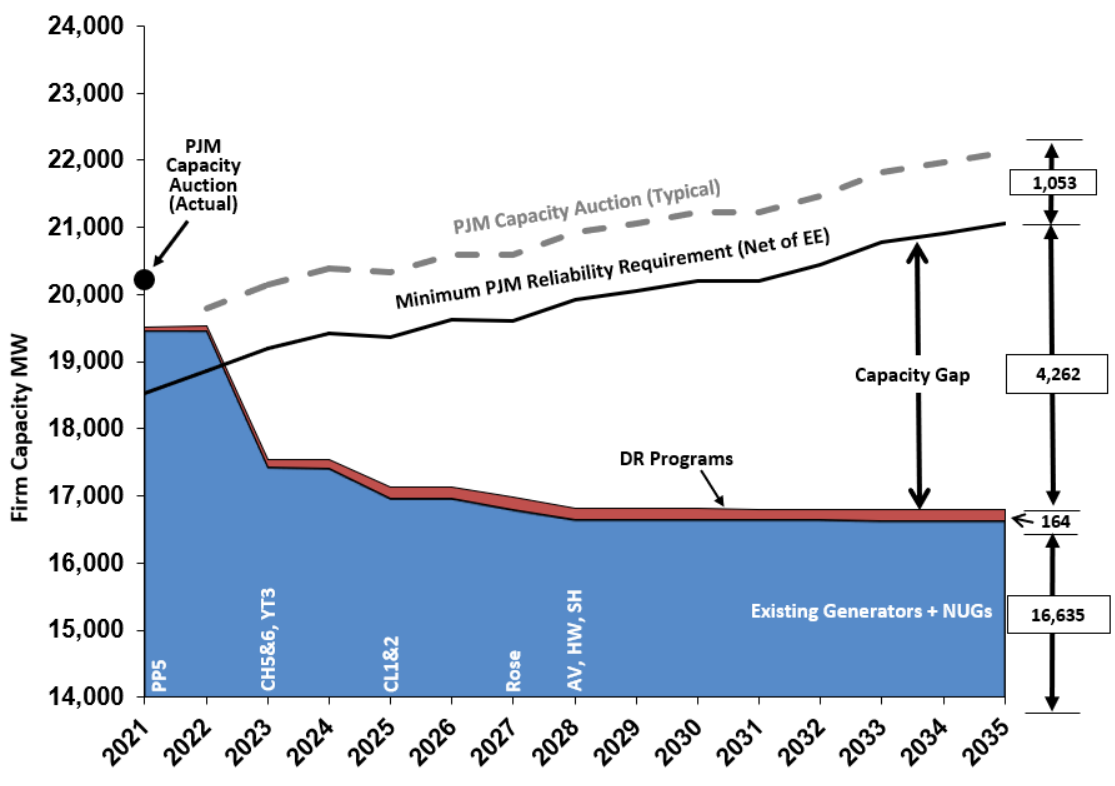
Chapter 2: Results of Integrated Planning Process

This chapter presents the results of the integrated planning process, including the Company's current capacity and energy positions, the Alternative Plans presented to meet the future capacity and energy needs of the Company's customers, and the net present value ("NPV") of each Alternative Plan. This section also includes the results of the initial transmission system reliability analysis related to the retirement of all Company-owned carbon-emitting generation in 2045, and the results of a Virginia residential bill analysis.

2.1 Capacity and Energy Positions

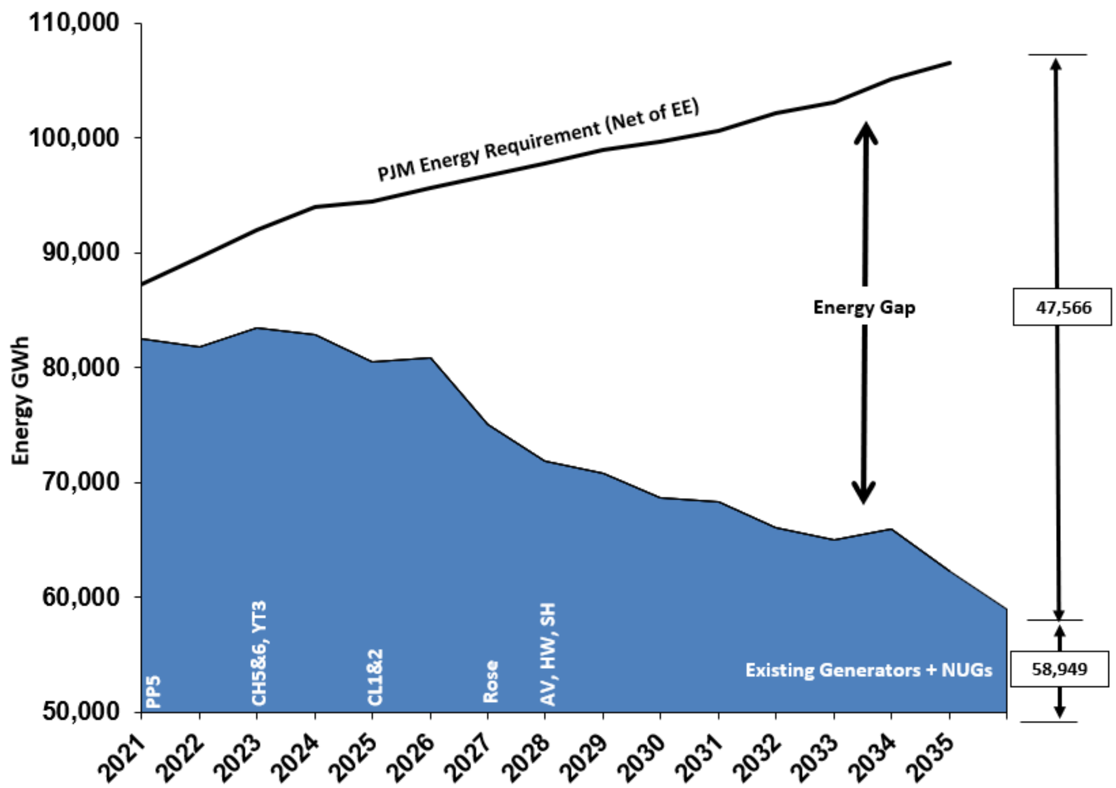
Figures 2.1.1 and 2.1.2 illustrate the Company's current capacity and energy positions using unit retirement assumptions for Alternative Plan B. After adjusting for energy efficiency, voltage optimization, and retail choice as discussed in Sections 4.1.3, 4.1.4, and 4.1.5, respectively, DOM LSE is expected to experience a compound annual growth rate ("CAGR") of 1.0% in future summer peak demand and 1.3% in energy requirements over the Planning Period.

Figure 2.1.1 - Current Company Capacity Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.1.2 - Current Company Energy Position (2021 to 2035)



Notes: "Existing Generators + NUGS" include generation under construction; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

2.2 Alternative Plans

The 2020 Plan presents a range of alternatives representing paths forward for the Company to meet the future capacity and energy needs of its customers. Notably, however, the build plans shown in Alternative Plans B through D do not fully account for possible system reliability and security issues. More planning work is necessary to test the grid under different conditions to ensure system reliability and security in the long term.

The Company's options for meeting customers' future capacity and energy needs are: (i) supply-side resources, (ii) demand-side resources, and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing rate stability, increasing energy independence, promoting economic development, incorporating input from stakeholders, and minimizing adverse environmental impact—will help the Company meet growing demand and achieve its clean energy goals while protecting customers from a variety of potential challenges.

Specifically, the Company presents four different Alternative Plans designed to meet customers' needs in the future under different scenarios, which were designed using constraint-based least-cost planning techniques:

- Plan A – This Alternative Plan presents a least-cost plan that estimates future generation expansion where there are no new constraints, including no new regulations or restrictions on CO_2 emissions. Plan A is presented for cost comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, this Alternative Plan does not represent a realistic state of relevant law and regulation.

- Plan B – This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues.

- Plan C – This Alternative Plan uses similar assumptions as Plan B, but retires all Company-owned carbon-emitting generation in 2045, resulting in close to zero CO_2 emissions from the Company's fleet in 2045. To reach zero CO_2 emissions in 2045, Plan C significantly increases the amount of energy storage resources and the level of imported power.

- Plan D – This Alternative Plan uses similar assumptions as Plan C, but changes the capacity factor assumption for future solar resources from 25% to 19%. As a result, Plan D significantly increases the amount of solar resources needed to reach zero CO_2 emissions in 2045.

Figures 2.2.1 through 2.2.4 show the build plans for each Alternative Plan. See Appendix 2A for the capacity and energy associated with all Alternative Plans.

Figure 2.2.1 - Alternative Plan A (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired	Nuclear	Retirements
2021									PP5
2022		480							
2023		480					485		YT3, CH5&6
2024		480					485		
2025		480					485		CL1&2
2026		480					485		
2027		480							Rosemary
2028		480							
2029		480							
2030		480							
2031		480							
2032		480						Surry 1	
2033		480						Surry 2	
2034		480							
2035		480							
TOTAL	**0**	**6,720**	**0**	**0**	**0**	**0**	**1,940**	**1,676**	**3,030**

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal).

Figure 2.2.2 - Alternative Plan B (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	600	360	220	852	400				
2027	600	360		1,704	500				Rosemary
2028	600	480	220						AV, HW, SH
2029	960	480			500				
2030	960	360	220			300			
2031	720	360							
2032	720	360			500			Surry 1	
2033	720	360						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	**9,660**	**5,160**	**1,100**	**5,112**	**2,414**	**300**	**970**	**1,676**	**3,183**

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.3 - Alternative Plan C (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	600	360	220	852	400				
2027	600	360		1,704	500				Rosemary
2028	600	480	220						AV, HW, SH
2029	960	480			500				
2030	960	360	220			300			
2031	720	360							
2032	720	360			500			Surry 1	
2033	720	360						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	9,660	5,160	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.4 - Alternative Plan D (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Pumped Storage	Natural Gas-Fired[1]	Nuclear	Retirements
2021									PP5
2022	540	240	220						
2023	600	360			14		485		YT3, CH5&6
2024	600	360	220				485		
2025	600	360							CL1&2
2026	960	360	220	852	400				
2027	960	480		1,704	500				Rosemary
2028	960	480	220						AV, HW, SH
2029	960	480			500				
2030	960	600	220			300			
2031	960	600							
2032	960	600			500			Surry 1	
2033	960	600						Surry 2	
2034	720	360		2,556	500				
2035	720	360							
TOTAL	11,460	6,240	1,100	5,112	2,414	300	970	1,676	3,183

Notes: (1) Natural-gas fired facilities are placeholders to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources (less than 3 MW), whether Company-owned or PPA; "OSW" = offshore wind; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Alternative Plans B, C, and D include 970 MW of natural gas-fired CTs as a placeholder to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities.

Figure 2.2.5 shows the CO_2 emissions from the Company's fleet for each Alternative Plan, while Figure 2.2.6 shows the regional CO_2 emissions for each Alternative Plan. Because the regional CO_2 emissions capture the effects of both energy imports and exports required to meet customer needs, the regional emissions are a better indicator of customers' impact on the environment.

Figure 2.2.5 – Virginia CO_2 Output from Company Fleet for Alternative Plans

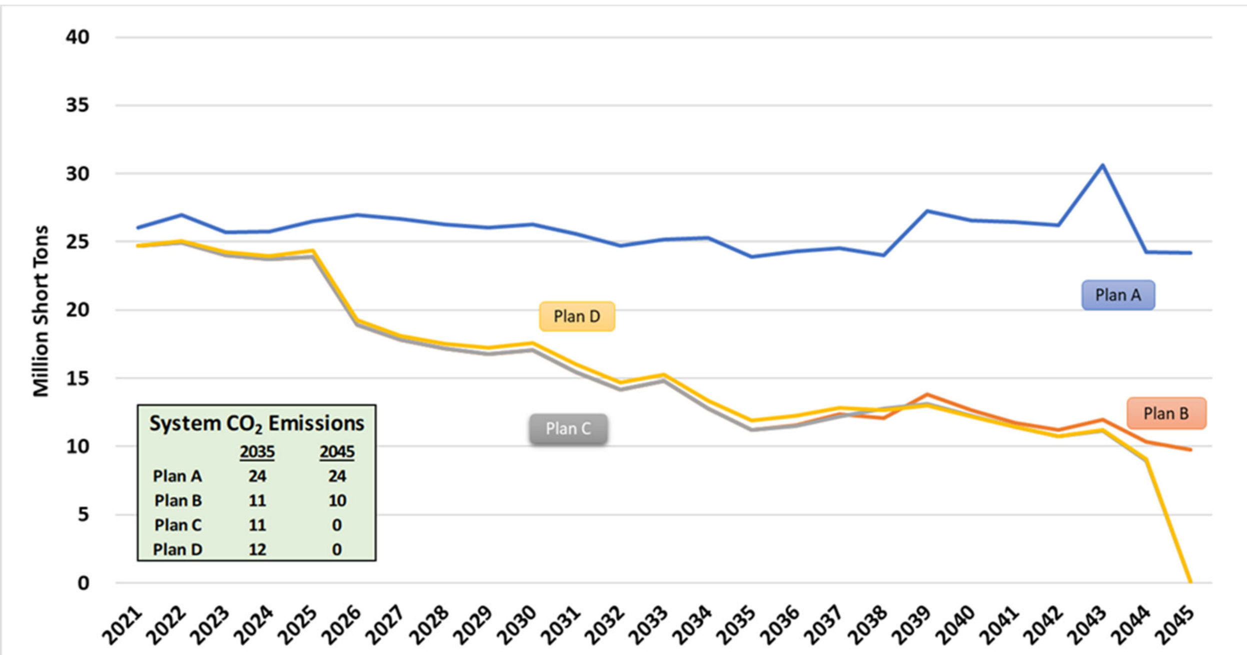
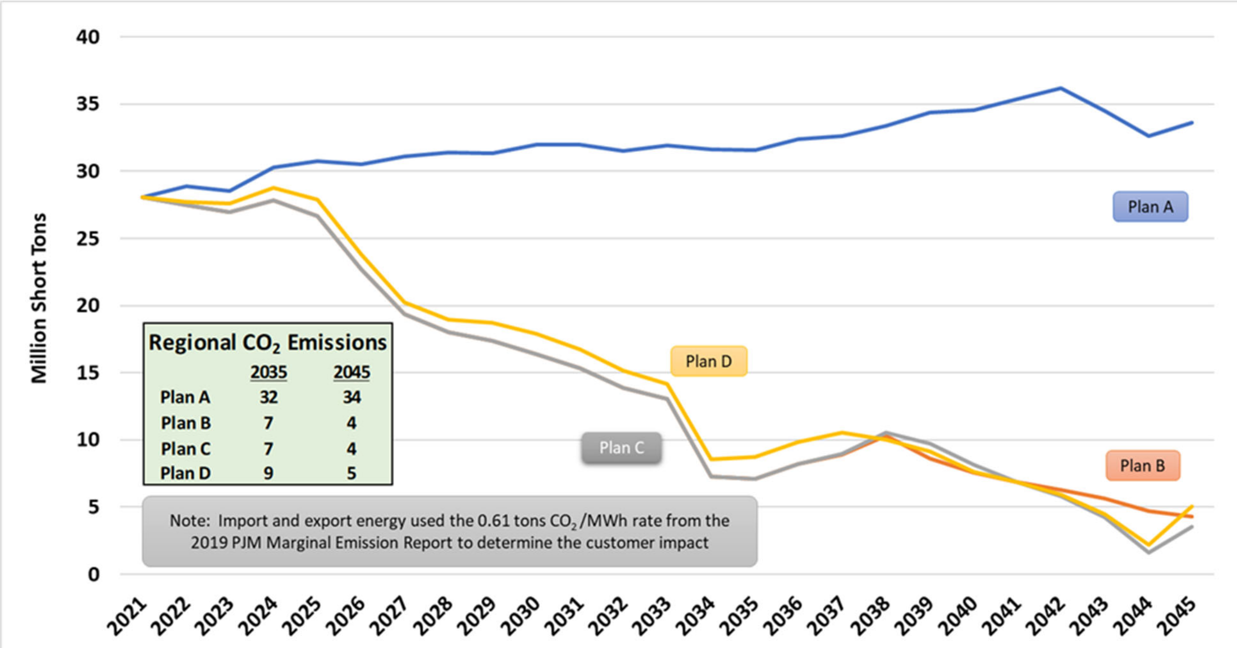


Figure 2.2.6 – Regional CO_2 Output for Alternative Plans



As seen in Figures 2.2.2 through 2.2.4, Plans B through D are all very similar over the first 15 years of each Alternative Plan. This alignment between Alternative Plans B through D over the 15-year Planning Period creates a common pathway for the Company to pursue now while allowing new technologies to emerge and mature, and allowing analysis and study to continue. Accordingly, for this 2020 Plan, the Company recommends a path forward that substantially aligns with the first 15 years of Alternative Plans B through D. Over the longer-term, however, based on current technology and this "snapshot in time," the Company recommends Alternative Plan B.

2.3 Transmission System Reliability Analysis

In order to understand the possible transmission system reliability implications of retiring all Company-owned carbon-emitting generation in 2045, as contemplated by Alternative Plans C and D, the Company performed a transmission system power flow analysis by developing a base power flow case and three different scenarios, and utilizing simplifying assumptions. The initial results of this analysis identified North America Electric Reliability Corporation ("NERC") reliability deficiencies on twenty-six 115 kV lines, thirty-two 230 kV lines, six 500 kV lines, and eleven transmission transformers that would need to be resolved to avoid NERC violations. In addition, the results indicated that Alternative Plans C and D would require construction of four interstate transmission lines at an estimated cost of $8.4 billion. A discussion of this analysis and the full results are provided in Section 7.5.

2.4 NPV Results

The Company evaluated the Alternative Plans to compare and contrast the NPV utility costs for each build plan over the Study Period. Figure 2.4.1 presents these NPV results on the "Total

System Costs" line, as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Figure 2.4.1 – NPV Results

2020 $B	Plan A	Plan B	Plan C	Plan D
Total System Costs[1]	$ 34.7	$ 56.8	$ 60.7	$ 63.0
GT Plan	$ 0.2	$ 3.2	$ 3.2	$ 3.2
SUP	$ 2.2	$ 2.2	$ 2.2	$ 2.2
Broadband	$ -	$ 0.2	$ 0.2	$ 0.2
Transmission Underground Pilot	$ -	$ 0.2	$ 0.2	$ 0.2
Transmission	$ 5.1	$ 5.1	$ 5.1	$ 5.1
Transmission Level Import Increase	$ -	$ -	$ 8.4	$ 8.4
Customer Growth	$ 2.0	$ 2.0	$ 2.0	$ 2.0
Subtotal Plan NPV[2]	**$ 44.3**	**$ 69.7**	**$ 82.1**	**$ 84.3**
Less Benefits of GT Plan	$ -	$ (3.5)	$ (3.5)	$ (3.5)
Total Plan NPV	**$ 44.3**	**$ 66.2**	**$ 78.6**	**$ 80.8**
Plan Delta vs. Plan A	**$ -**	**$ 21.9**	**$ 34.3**	**$ 36.6**

Notes: (1) Total system costs include the results from Figures 2.2.1 through 2.2.4 plus approved, proposed, and generic DSM; solar interconnection costs; and solar integration costs. (2) Numbers may not add due to rounding.

2.5 Virginia Residential Bill Analysis

The bill of a typical residential customer in Virginia using 1,000 kWh per month as of December 31, 2019, was $122.66. As of May 1, 2020, this typical bill is $116.18, largely attributable to a significant decrease in the fuel factor. The Company calculated the projected residential bill for Alternative Plans A and B over each of the next ten years. Figure 2.5.1 presents the summary results of these projections in 2030, as well as the CAGR. Importantly, these bill projections are not final—all Company rates are subject to regulatory approval. Additionally, the bill projection associated with Alternative Plan A is presented for comparison purposes only in compliance with SCC orders. Given the legislation that will take effect in Virginia on July 1, 2020, Plan A does not represent a realistic state of relevant law and regulation.

As can be seen in Figure 2.5.1, about 40% of the projected bill increase from 2020 to 2030 is associated with investments incentivized or mandated by the VCEA and other legislation from the 2020 Regular Session of the Virginia General Assembly. Roughly one-third is attributable to compliance with directives that pre-date 2020, including the GTSA. Overall, the projected bill increase is approximately 2.9% on a compound annual basis using year-end 2019 customer bill as a baseline. The Company used year-end 2019 for this calculation to compare full-year data points. For comparison, in 2008, the year following passage of the Virginia Electric Utility Regulation Act, the bill of a typical residential customer in Virginia using 1,000 kWh per month was $107.20. Using 2008 as a baseline, the projected compound annual growth rate in the typical residential customer bill through 2030 is approximately 2.1%.

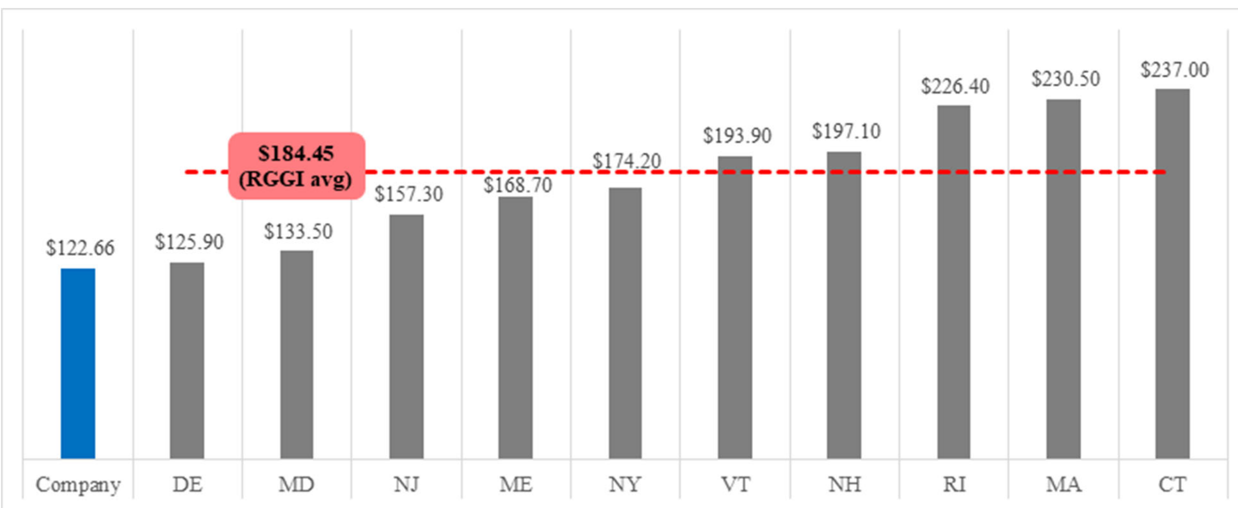
Figure 2.5.1 – Residential Bill Projection (1,000 kWh per Month)

	2030	CAGR
2019 Year End	$122.66	
Plan A[1]	$11.70	0.8%
Pre-2020 Legislation[2]	$15.28	1.0%
2020 Legislation[3]	$18.94	1.1%
Total 2030 Year End	**$168.58**	**2.9%**
Total Bill Increase	$45.92	

Notes: (1) Represents bill projections associated with future generation in Alternative Plan A; approved and proposed investments in DSM; approved investments in the Grid Transformation Plan (*i.e.* Phase IA and IB); investments in the Strategic Underground Program; and compliance with environmental laws and regulations, including CCR investments. (2) Represents bill projections associated with future generation in Alternative Plan B and other investments incentivized or mandated by legislation prior to 2020, including legislation related to pumped storage (2017), the GTSA (2018), and rural broadband (2019). (3) Represents bill projections associated with future generation in Alternative Plan B and other investments incentivized or mandated by the VCEA and other 2020 legislation.

For perspective, the average residential rate for RGGI states normalized for 1,000 kWh monthly usage—approximately $184.45—is approximately 50% higher than the Company's typical residential bill as of year-end 2019 (*i.e.*, $122.66). See Figure 2.5.2.

Figure 2.5.2 – Residential Bill Comparison for RGGI States[1]



Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of February 2020, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company as of year-end 2019.

Chapter 3: Short-Term Action Plan

The short-term action plan provides the Company's strategic plan for the next five years (2020 to 2025). Generally, the Company plans to proactively position itself in the short-term to meet its commitment to clean energy for the benefit of all stakeholders over the long term. The Company also plans to continue its analyses on how to meet both its clean energy goals and the requirements of the VCEA while continuing to provide safe and reliable service to its customers. As shown in Figures 2.2.2 through 2.2.4, Alternative Plans B through D present the same path forward in the next five years, and substantially similar paths over the next 15 years.

3.1 Generation

Over the next five years, the Company expects to take the following actions related to existing and proposed generation resources:

- File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the RPS requirements established by the VCEA, including related requests for approval of certificates of public convenience and necessity and for prudence determinations related to PPAs;
- Continue the construction of the CVOW demonstration project;
- Continue development and begin construction of a larger build-out of offshore wind off the coast of Virginia;
- Meet its targets under the Virginia RPS at a reasonable cost and in a prudent manner by: (i) applying renewable energy from existing generating facilities, including NUGs; (ii) constructing and operating new renewable energy facilities and energy storage facilities; (iii) purchasing cost-effective RECs, including optimizing RECs produced by Company-owned generation (*i.e.*, when higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS requirements);
- Meet its target under North Carolina Renewable Energy Portfolio Standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan;
- Support ongoing Nuclear Regulatory Commission ("NRC") review of the subsequent license renewal application submitted for Surry Units 1 and 2 in October 2018;
- Submit an application to the NRC for the subsequent license renewal for North Anna Units 1 and 2 by the end of 2020;
- Continue developmental work for 300 MW of new pumped hydroelectric storage in southwestern Virginia;
- Achieve a minimum of 10% electricity production at VCHEC through the use of renewable waste wood by the end of 2021;
- Continue to make investments at existing generation units needed to comply with environmental regulations;
- In order to preserve the option to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities in the near term, evaluate sites and equipment for the construction of gas-fired CT units;

- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements; and
- Enhance access to natural gas supplies, including shale gas supplies from multiple supply basins.

Appendices 3A and 3B provide further details on each generation project under construction and under development, respectively. Appendix 3C provides a comparison of the short-term action plan for generation resources in this 2020 Plan compared to the 2018 Plan.

3.2 Demand-Side Management

Over the next five years, the Company will continue to identify and propose new or revised DSM programs that meet the existing requirements of the GTSA and the new requirements and targets in the VCEA in conjunction with the DSM stakeholder process. The Company also expects to complete a new market potential study in late 2020, and will work with stakeholders through the existing stakeholder processes towards development of a long-term strategy to achieve legislative requirements in both the GTSA and VCEA as they relate to energy efficiency.

In Virginia, the Company filed its Phase VIII DSM application in December 2019 seeking approval of 11 DSM programs and an extension of one existing program. The SCC must issue its final order on this application by August 2020.

In North Carolina, the Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that have been approved in Virginia that continue to meet Company requirements for new DSM resources. For programs that are not approved by the SCC, the Company will evaluate the programs on a North Carolina-only basis.

3.3 Transmission

Over the next five years, the Company will continue to assess its transmission system and to construct facilities required to meet the needs of its customers. Generally, the Company anticipates transmission projects that are needed to rebuild aging infrastructure and to interconnect data center customers. The Company also intends to pursue an additional underground transmission line project under the pilot program established by the GTSA as modified by House Bill No. 576 from the 2020 Regular Session of the Virginia General Assembly, which was signed into law on March 4, 2020. Appendix 3D provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM.

The Company will also explore options to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities. Finally, the Company will continue its long-term analysis of the actions and costs associated with the retirement of dispatchable carbon-emitting generating units and the integration of large volumes of intermittent renewable generation on the transmission system.

3.4 Distribution

Over the next five years, the Company will continue to assess its distribution system, adapt the distribution grid to meet the needs of a modernized system, and implement solutions and programs to meet the needs of its customers both today and in the future. Specifically, the Company expects to take the following actions related to its distribution system:

- Implement the Grid Transformation Plan, including initiatives to facilitate the integration of DERs, enhance grid reliability and security, and improve the customer experience;
- Publish hosting capacity maps for both utility scale and net metering DERs;
- Continue to develop integrated distribution planning capabilities, including a standardized screening process to consider non-wires alternatives for distribution grid support;
- Continue its Strategic Undergrounding Program ("SUP");
- Pilot V2G technology through the Electric School Bus Program;
- Pilot BESS as grid support resources; and
- Participate in the rural broadband pilot program.

Chapter 4: Generation – Planning Assumptions

The generation planning 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 and energy needs to maintain reliable service for its customers over the Study Period. The Company also completes a retirement analysis on certain existing supply-side resources to determine the economic feasibility of those resources. Next, a feasibility screening, followed by a busbar screening curve analysis, is conducted to identify a set of future supply-side resources potentially available to the Company, along with their individual characteristics, using input assumptions such as load, fuel prices, emissions costs, maintenance costs, and resource costs. Additionally, the Company incorporates the cost-benefit screening used to determine demand-side resources that could potentially fit into the Company's resource mix. These potential resources and their associated economics are next incorporated into the PLEXOS model—a utility modeling and resource optimization tool—along with any regulatory requirements (*e.g.*, the requirements in the VCEA). The Company then develops a set of alternative plans using PLEXOS that represent future paths forward considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against scenarios that may occur given future market and regulatory uncertainty. The NPV utility costs from PLEXOS include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

The Company currently models its system in PLEXOS based on hourly data. This 2020 Plan does not incorporate sub-hourly analysis because the Company is still developing the inputs required for such an analysis. Sub-hourly analysis will require sub-hourly inputs based on historical performance for all resource type that could represent the operating characteristics of those resource for future projections. In addition, the Company must use internal information to establish the adjusted reserve margin and coincidence factor, because PJM does not provide this level of detail. Nevertheless, the Company intends to incorporate sub-hourly analysis in future Plans and update filings once the required inputs and processes are developed and validated. This sub-hourly analysis would capture the potential benefits from ancillary service markets. For example, sub-hourly analysis would be able to capture the benefits that battery energy storage systems could offer to the regulating services.

In this 2020 Plan, the Company relies on several assumptions for its integrated resource planning process. This chapter discusses these assumptions related to load forecast, capacity needs, capacity value, commodity prices, RPS, solar, storage, gas transportation, the least-cost plan, and the VCEA. The Company updates its assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.1 Load Forecast

The 2020 Plan presents two load forecasts: (i) the 2020 PJM Load Forecast and (ii) the 2020 Company Load Forecast. The 2020 PJM Load Forecast was used in the development of all Alternative Plans. Because of the limited nature of the information provided by PJM, however, the Company presents and discusses the 2020 Company Load Forecast as well, and presents a sensitivity using the Company Load Forecast. Figures 4.1.1 and 4.1.2 compare these two load forecasts, and provide historical peak load and energy. To provide an apples-to-apples comparison of peak load, the Company added back behind-the-meter generation resources to the PJM Load Forecast.

Overall, the PJM Load Forecast anticipates summer peak demand and energy CAGR for the Dominion Energy Zone ("DOM Zone") of approximately 1.0% and 1.3%, respectively, over the Planning Period. The Company's Load Forecast anticipates DOM Zone summer peak demand and energy forecast CAGR of 1.2% and 1.4%, respectively.

Figure 4.1.1 - DOM Zone Peak Load Comparison

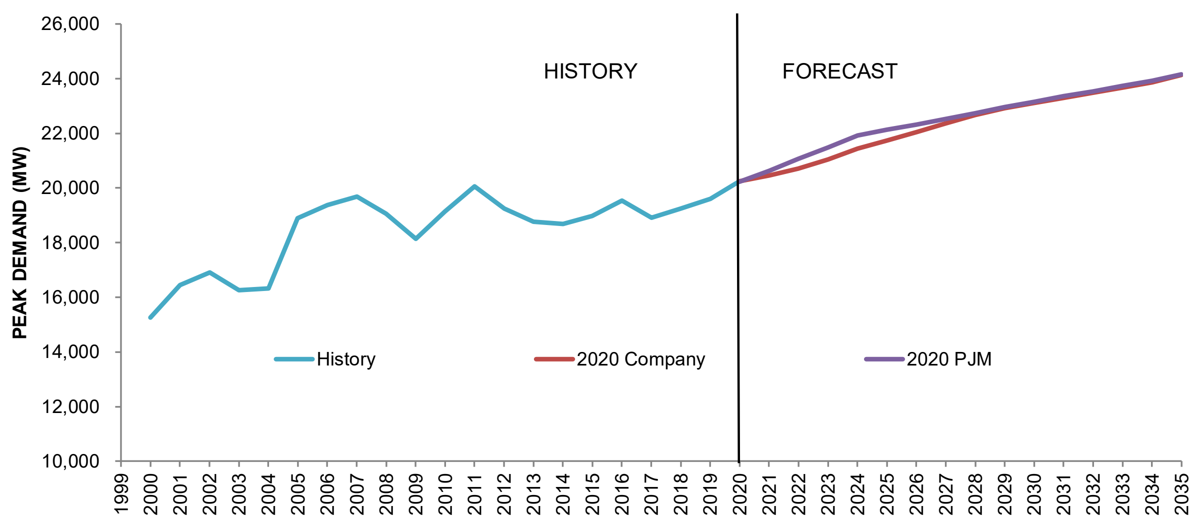
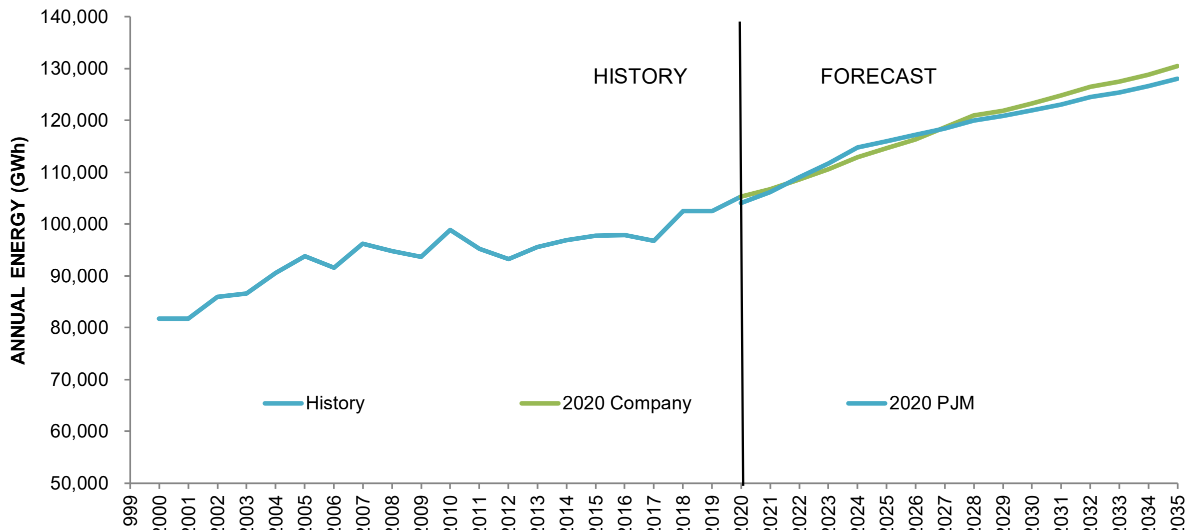


Figure 4.1.2 - DOM Zone Annual Energy Comparison



A 10-year history and 15-year forecast of sales and customer count at the system level, as well as a breakdown at Virginia and North Carolina levels, are provided in Appendices 4A through 4F. Appendix 4G provides a summary of the summer and winter peaks used in the Company Load Forecast. The 3-year actual and 15-year forecast of summer and winter peak, annual energy, DSM peak and energy, and system capacity are shown in Appendix 4H. Appendix 4I provides the reserve margins for a 3-year actual and 15-year forecast, and Appendix 4J provides the 3-year actual and 15-year forecast summer and winter peaks to show seasonal load. Finally, the 3-year historical load and 15-year projected load for wholesale customers are provided in Appendix 4K. See Appendix 4L for load duration curves for the years 2020, 2025, and 2035 with and without DSM. The information provided in Appendices 4A through 4F and 4K use the Company Load Forecast because PJM does not provide this level of detail.

Notably, neither the 2020 PJM Load Forecast nor the Company Load Forecast incorporates any effects on load of the ongoing public health emergency related to the spread of COVID-19.

4.1.1 PJM Load Forecast

The Company utilized the DOM Zone load forecast as published by PJM in its 2020 PJM Load Forecast Report dated January 2020 in the development of Alternative Plans A through D included in this 2020 Plan. The PJM website (www.PJM.com) contains information on the methods used by PJM in developing this forecast.

To properly use the PJM Load Forecast in the development of this 2020 Plan, the Company needed to adjust that forecast for modeling purposes. Because the PJM Load Forecast only provides a 15-year forecast, PJM's 15-year CAGR of 1.0% and 1.3% was used to extend the summer peak demand and energy forecasts, respectively, for years 2035 through 2045. Since PJM does not provide a DOM LSE forecast, the Company then scaled down the PJM DOM Zone coincident peak load forecast and energy forecast. This required the Company to adjust PJM's DOM Zone forecasts by a percentage factor calculated using a regression technique that utilized historical peak and energy data over the preceding 10-year period. Figure 4.1.1.1 presents the forecast extension and the DOM Zone adjustment.

Figure 4.1.1.1 – PJM Load Forecast Adjusted to LSE Requirements

Year	DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM Zone Energy (GWh)	DOM LSE Equivalent (GWh)
2021	19,486	16,802	104,845	90,435
2022	19,837	17,105	107,471	92,700
2023	20,178	17,339	110,012	94,893
2024	20,462	17,644	112,951	97,428
2025	20,651	17,807	114,053	98,378
2026	20,880	18,004	115,176	99,347
2027	21,072	18,170	116,343	100,353
2028	21,250	18,323	117,880	101,679
2029	21,404	18,456	118,745	102,426
2030	21,572	18,601	119,722	103,269
2031	21,756	18,759	120,756	104,160
2032	22,008	18,977	122,161	105,372
2033	22,176	19,121	122,831	105,950
2034	22,326	19,251	123,897	106,870
2035	22,249	19,357	125,114	107,920
2036	22,686	19,561	126,752	109,333
2037	22,926	19,768	128,412	110,765
2038	23,168	19,977	130,093	112,215
2039	23,413	20,188	131,797	113,685
2040	23,661	20,402	133,522	115,174
2041	23,911	20,617	135,270	116,682
2042	24,163	20,835	137,042	118,210
2043	24,419	21,055	138,836	119,758
2044	24,677	21,278	140,654	121,326
2045	24,938	21,503	142,495	122,915

Next, the Company needed to adjust the PJM Load Forecast to properly incorporate it into PLEXOS. Planning models, including PLEXOS, require 8,760-hour (*i.e.*, the total hours in a year) load shapes ("8,760 load shapes") as a necessary input. PJM does not provide forecasted 8,760 load shapes. Instead of attempting to generate 8,760 load shapes for PJM, the Company adjusted a historical DOM LSE summer peak 8,760 load shape to meet the annual coincident peak demand and energy derived from the 2020 PJM DOM Zone Load Forecast.

PJM's practice is to adjust their load forecasts downward for current and forecasted DERs, which includes a forecast for net metering customers. Given this practice, all PLEXOS modeling that utilized the PJM Load Forecast in this 2020 Plan excluded DERs (including net metering customers) from the supply options.

One final note regarding the 2020 PJM Load Forecast is that PJM developed several revisions to its load forecasting process in 2019. Because of those changes, PJM now considers the DOM Zone to be a winter peaking zone. In other words, the winter peak demand forecast for the DOM Zone now exceeds the summer demand peak in all years of the forecast period according to PJM.

Given that the PJM RTO is still a summer peaking entity, however, PJM will still procure capacity for the DOM Zone at levels commensurate with the DOM Zone coincident summer peak forecast. As such, the Company developed this 2020 Plan using a summer peak 8,760 shape modified to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

4.1.2 Company Load Forecast

This 2020 Plan also includes the Company's internally developed peak demand and energy forecast. The Company ran a sensitivity on Alternative Plan B, re-optimizing the build plan based on use of this internally developed forecast instead of the PJM Load Forecast. Figure 4.1.2.1 displays the results of this sensitivity analysis.

Figure 4.1.2.1 - Load Forecast Sensitivity

	Plan B	**Plan B Load Forecast Sensitivity**
Load Forecast	PJM	Company
NPV Total	$66.2 B	$66.8 B
Solar (MW)	15,920 15-year 31,400 25-year	15,920 15-year 31,400 25-year
Offshore Wind (MW)	5,112 15-year 5,112 25-year	5,112 15-year 5,112 25-year
Storage (MW)	2,714 15-year 5,114 25-year	2,714 15-year 5,114 25-year
Combustion Turbine (MW	970 15-year 970 25-year	970 15-year 970 25-year
PJM Imports (MW)	5,200 15-year 5,200 25-year	5,200 15-year 5,200 25-year
Retirements (MW	3,183 15-year 5,414 25-year	3,183 15-year 5,414 25-year

As can be seen, the Company Load Forecast produces the same build plan as the PJM Load Forecast, all other Plan B assumptions being equal. The NPV is slightly higher using the Company Load Forecast because the Company would need to purchase additional energy in the later years of the Study Period. These results confirm that the two forecasts are very similar. In addition, it shows that the main driver for the units selected in the build plan for Alternative Plan B was the requirements of the VCEA, not the load forecast.

The following paragraphs describe the Company's internal load forecasting process, plus the new revisions to that process that were incorporated since the 2018 Plan was published.

Methodology

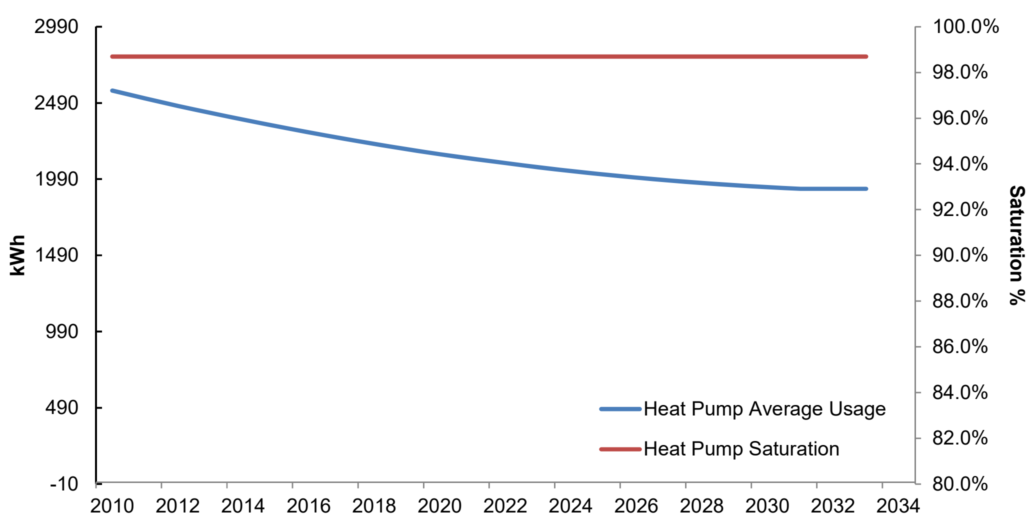
The Company uses two econometric models with an end-use orientation to forecast sales, energy, and peak demand. The first is a customer class level sales model ("Sales Model") and the second is a system level hourly load model ("Peak and Energy Model"). The models used to produce the Company Load Forecast have been developed, enhanced, and re-estimated annually for over 20 years. Both models were estimated over a rolling 15-year historical period as each long-term forecast is developed.

Sales Model

The Sales Model incorporates separate monthly sales equations for residential, non-data center commercial, industrial, public authority, street and traffic lighting, and wholesale customer classes, as well as other LSEs in the 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. In addition to developing a sales forecast, the primary role of the Sales Model is to provide estimates of historical and projected weather sensitive appliance stocks and non-weather sensitive base demand for use as exogenous variables in the Peak and Energy Model.

The residential sales equation also relies on an algorithm that dynamically adjusts forecasted appliance saturation and usage based on historical trends. These historical trends are determined from appliance data collected through surveys of the Company's residential customers. Figure 4.1.2.2 shows historical and forecasted saturation and usage data for residential heat pumps.

Figure 4.1.2.2 – Residential Heat Pump (Cooling) Saturation and Usage



The next residential and commercial customer appliance survey and subsequent conditional demand analysis will be completed in the second half of 2020.

The Company has performed out-of-sample testing on its Sales Model for the residential, commercial, industrial, and public authority (government) customer classes. The results of tests are included in the Company's load forecasting model documentation.

Peak and Energy Model

The Company's second model, the Peak and Energy Model, is comprised of 24 separate equations, one for each hour of the day, with adjusted DOM Zone loads as the dependent variable. Prior to estimating the Peak and Energy Model equations, historical hourly loads are adjusted by adding back historical distributed solar generation and load management reductions. This adjustment is performed in order to ascertain the true load rather than a load that is masked by these devices. The Company's practice is to account for distributed solar and load management programs as supply resources, not as a load modifier.

The Peak and Energy Model equations include a non-weather sensitive base demand variable, derived from the estimated aggregate non-weather sensitive base demand components from the Sales Model as well as a detailed specification of weather variables. The weather variables include interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations in conjunction with residential heating and cooling appliance stocks. The Peak and Energy Model also employs indicator variables to capture monthly, day of week, time of day, holiday, and other seasonal effects, as well as unusual events such as hurricanes that produce widespread outages.

The forecast of expected DOM Zone monthly and seasonal peaks and energy output is produced by simulating hourly demands from the estimated Peak and Energy Model over actual hourly weather from each of the past 15 years under projected economic conditions. The final forecasted zonal peak and energy values include subsequent adjustments for projected data centers, EVs, or other significant load additions not reflected in the hourly regression equations.

The final monthly peak and energy forecast for the DOM LSE is based on a regression of historical DOM LSE loads onto historical DOM Zone loads. The estimated coefficients are applied to the projected zonal loads resulting in a load forecast for the DOM LSE that is then adjusted for known firm contractual obligations in the forecast period.

Data Center Forecast

Data center sales, energy, and peak demand are now being forecasted by the Company as a standalone category and are being applied to the Company's sales, peak, and energy forecasts as an exogenous adjustment. This action is consistent with a forecasting recommendation provided by Itron Inc. ("Itron"), as discussed below. Figures 4.1.2.3 and 4.1.2.4 reflect the data center peak and energy forecast, respectively.

Figure 4.1.2.3 – Data Center Peak Demand Forecast

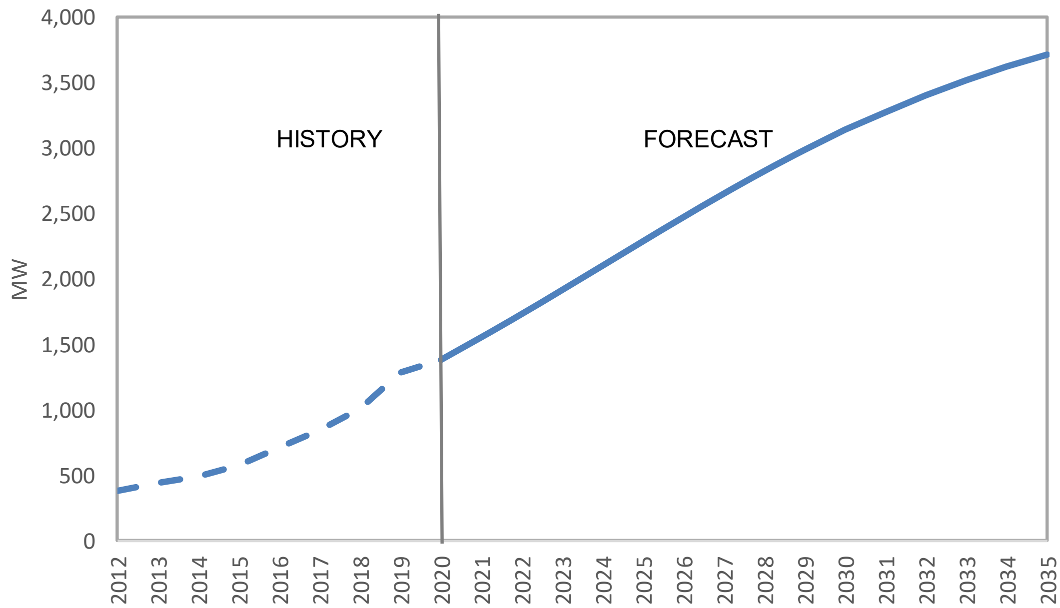
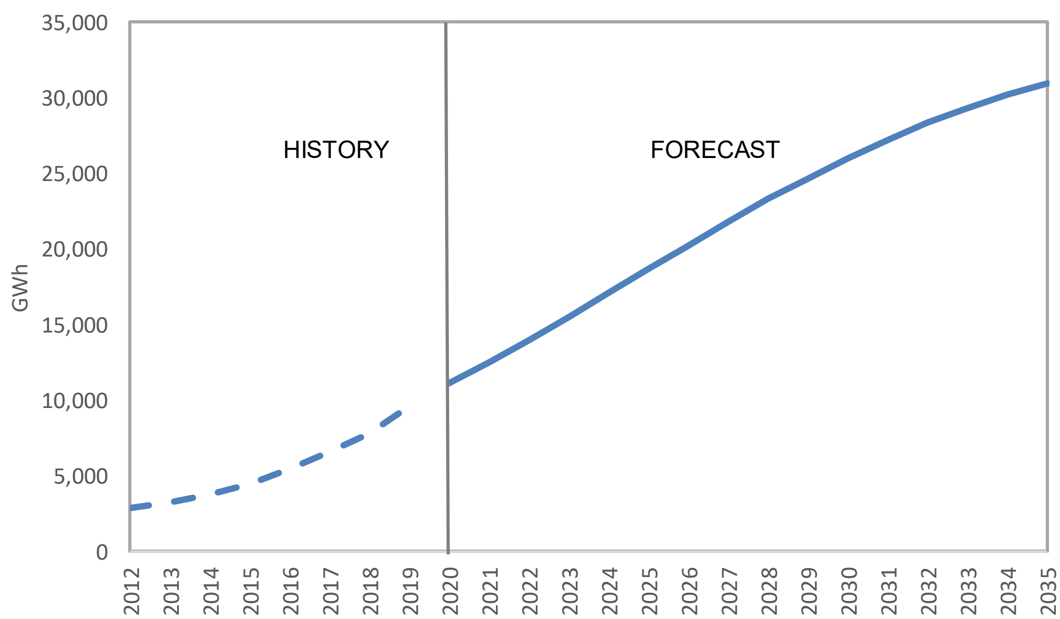


Figure 4.1.2.4 – Data Center Energy Forecast



Electric Vehicle Forecast

The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. For this 2020 Plan, the Company has revised its EV forecasting process. Like data centers, the Company now subtracts EV sales from history and re-estimates the residential and commercial sales models. Also, like data centers, a separate EV forecast is developed and added to the appropriate residential or commercial sales forecast as a model post-processing adjustment. The EV forecast was developed by Navigant Consulting, Inc. ("Navigant"). The Company used this same EV forecast to develop the recently-approved Smart Charging Infrastructure Pilot Program, a component of its Grid Transformation Plan discussed further in Section 8.3. The only modification to the Navigant forecast was that the Company extended the forecast from 10 years to 25 years using the same long-term growth rates calculated from the forecast itself. Figures 4.1.2.5 and 4.1.2.6 reflect the EV peak and energy forecast, respectively.

Figure 4.1.2.5 – Electric Vehicle Peak Demand Forecast

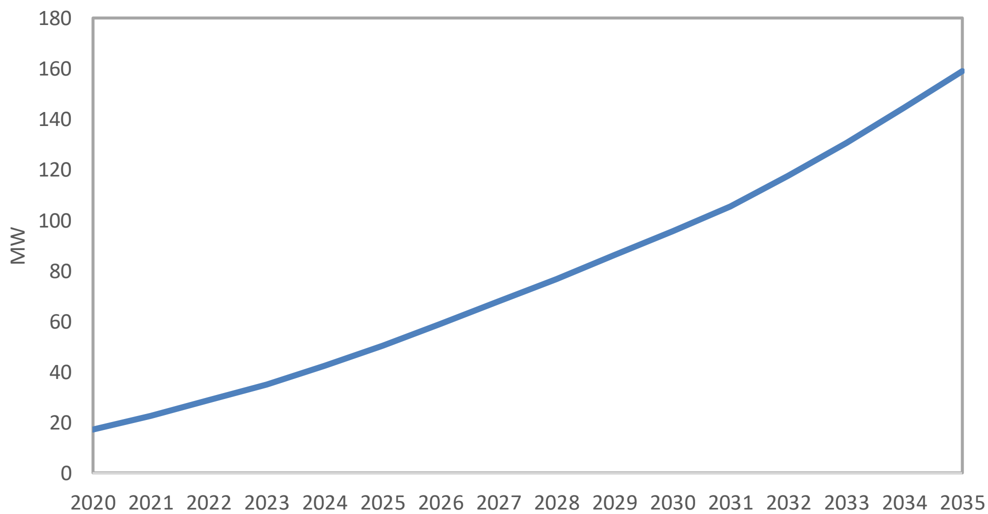
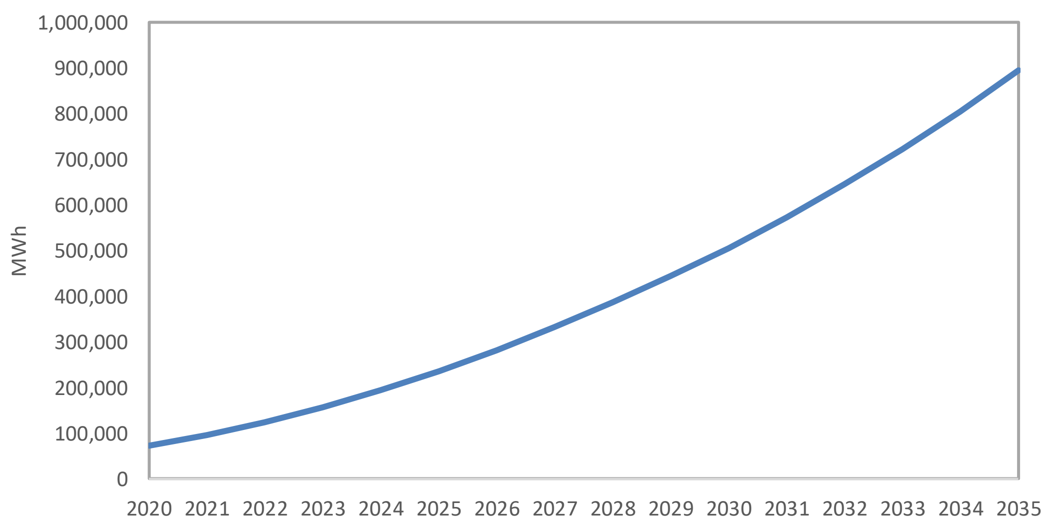


Figure 4.1.2.6 – Electric Vehicle Energy Forecast



Independent Review of the Company's Load Forecasting Process

In response to feedback received during the 2018 Plan proceeding, the Company engaged Itron in 2019 to (i) review its load forecasting process and methods and (ii) perform a long term (*i.e.*, greater than 5 years) study of data center growth within the Company's service territory. Overall, Itron concluded that the Company's load forecast methodology provides reasonable projections for long-term resource planning, and offered general recommendations that could improve that approach. The Company has incorporated the following load forecast recommendations into this 2020 Plan:

- Itron recommended that the Company shorten the coefficient estimation period from the Company's traditional period of 30 years. Consistent with this recommendation, the 2020 Company Load Forecast utilized 15 years of history to re-estimate the model and also used 15 years of weather history in its weather normalization process.
- Itron recommended that the Company isolate the data center loads from commercial sales and system hourly loads. Consistent with this recommendation, the 2020 Company Load Forecast removed the data center peak demand and energy from the commercial sector and estimated each sector (*i.e.*, non-data center commercial and data centers) independently.

The Company will continue to review the results of the Itron study and incorporate recommendations into its load forecasting process as appropriate.

Itron also made several findings regarding long-term data center growth, including:

- With continuing demand growth for offsite computing and cloud-based computer service, strong Northern Virginia data center demand is expected to grow well into the future;
- Data center demand is expected to increase 176 MW on average per year between 2020 and 2030; and
- Utilizing the Bass Diffusion Model is a reasonable approach to forecasting long-term data center growth.

Economic and Demographic Assumptions

The economic and demographic assumptions that were used in the Company Load Forecast models were supplied by Moody's Analytics, prepared in October 2019, and are included as Appendix 4M. Figure 4.1.2.7 summarizes the economic variables used to develop the Company's sales and peak load forecasts.

Figure 4.1.2.7 - Major Assumptions for the Sales and Peak and Energy Models

	2020	2035	Compound Annual Growth Rate (%) 2020 - 2035
DEMOGRAPHIC:			
Customers (000)			
Residential	2,373	2,754	1.00%
Commercial	247	279	0.81%
Population (000)	8,627	9,341	0.53%
ECONOMIC:			
Employment (000)			
State & Local Government	545	616	0.82%
Manufacturing	244	202	-1.25%
Government	728	800	0.63%
Income ($)			
Per Capita Real disposable	47,758	62,345	1.79%
Price Index			
Consumer Price (1982-84=100)	261	368	2.33%
VA Gross State Product (GSP)	497	659	1.90%

Note: (1) "State & Local Government" = State (Commonwealth of Virginia) + Local (County + Municipalities)
(2) "Government" = State (Commonwealth of Virginia) + Local (County + Municipalities) + Federal Employment (Non-Military)

Explanatory Variable Comparison

The Company relies on Virginia economic explanatory variable forecasts supplied by third parties in the development of its load forecast for the DOM Zone. The supplier of these explanatory variable forecasts for the 2020 Company Load Forecast was Moody's Analytics ("Moody's"); PJM also used explanatory variables from Moody's in the development of its 2020 Load Forecast.

In past proceedings, questions have arisen about the use of Moody's and whether other entities could provide such forecasts. To the Company's knowledge, the only other reputable supplier of these forecast variables is IHS Markit ("IHS"). For direct comparison purposes in this 2020 Plan, the Company procured Virginia economic variable forecasts from both Moody's and IHS. Appendix 4N provides charts comparing different relevant variables. As shown in Appendix 4N, except for housing permits, IHS forecasts are similar to or higher than Moody's. The Company uses the housing permit forecast as an input variable in its residential load forecasting process to determine the number of residential customers. The residential load forecast also incorporates other input variables, such as disposable income forecast. If the Company had used IHS's economic variable forecasts instead of Moody's, it is likely that the residential sales results would be similar because while IHS's housing permit forecast is lower than Moody's, IHS's disposable income forecast is higher.

Net Metering Forecast

The Company has developed a process that can forecast residential and commercial net metering customers on a feeder level basis. This forecasting method can be used by the Company in forecasting future net metering supply-side resources. It cannot be used when using the PJM Load Forecast because PJM calculates behind-the-meter (including net metering) resources using different methods and reduces its overall load forecast by the determined values.

The net metering forecast process is composed of two components. The first component is the three parameter Bass Diffusion Model ("BDM") and the second component is a logit classification model. On a feeder level basis, the BDM is fit to actual net metering customer data to determine the first two parameters of the BDM, which are the coefficient of innovation and the coefficient of imitation. The logit classification model is used to determine the maximum number of potential customers that will elect to implement net metering technology at their premises using demographic information such as premises size, age, and value. This maximum number of potential customers figure is then utilized within the BDM framework as the third parameter to determine the leveling off point or the 100% saturation level of the BDM. This process will determine the net metering customer forecast, which is then translated into kWh using feeder averages for single unit size and capacity factor. The methods should prove valuable as the Company's distribution planners proceed with feeder assessments as part of evolving integrated distribution planning capabilities.

Wholesale Power Sales

The Company currently provides full requirement wholesale power sales to three entities, which are included in the Company Load Forecast. Appendix 4K provides a list of wholesale power sales contracts with parties to whom the Company has either committed or expects to sell power during the Planning Period.

Results

The DOM Zone is typically a summer peaking system. The all-time summer unrestricted peak demand for the DOM Zone is 20,328 MW and was set in the summer of 2011. On July 20, 2019, the DOM Zone unrestricted peak demand was 20,161 MW. The peak-producing weather event that drove this 2019 summer demand culminated on a Saturday. The Company estimates that had this weather pattern culminated on a weekday, the load would have been approximately 500 MW higher, thus resulting in a new all-time summer peak demand of 20,661 MW. However, during the winter periods of 2013/2014, 2014/2015, 2017/2018, and 2018/2019, significant DOM Zone unrestricted peaks were set at 19,978 MW, 21,867 MW, 21,350 MW, and 20,104 MW, respectively. Nevertheless, based on its load forecasting process—and unlike PJM—the Company still considers the DOM Zone to be a summer-peaking zone through 2031.

The historical DOM Zone summer peak growth rate has averaged about 1.3% annually over the 2004 to 2019 period. The annual average energy growth rate over the same period is approximately 0.8%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figures 4.1.2.8 and 4.1.2.9. Figure 4.1.2.8 also reflects the actual winter peak demand. DOM LSE peak and energy requirements are both estimated to grow annually at an approximate CAGR of 1.3% and 1.4%, respectively, throughout the Planning Period.

Figure 4.1.2.8 – DOM Zone Peak Load Based on Company Load Forecast

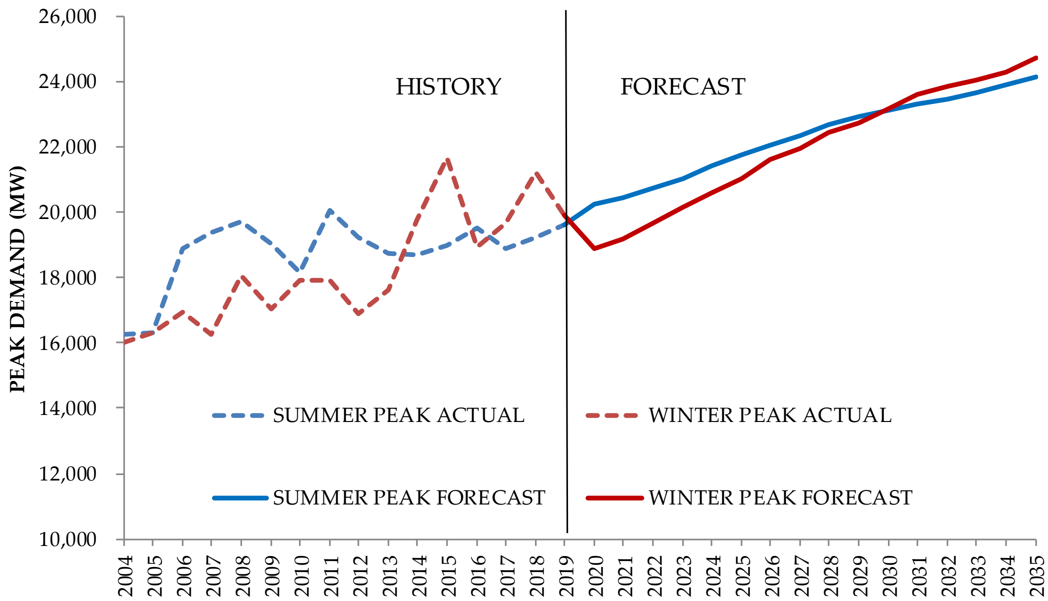
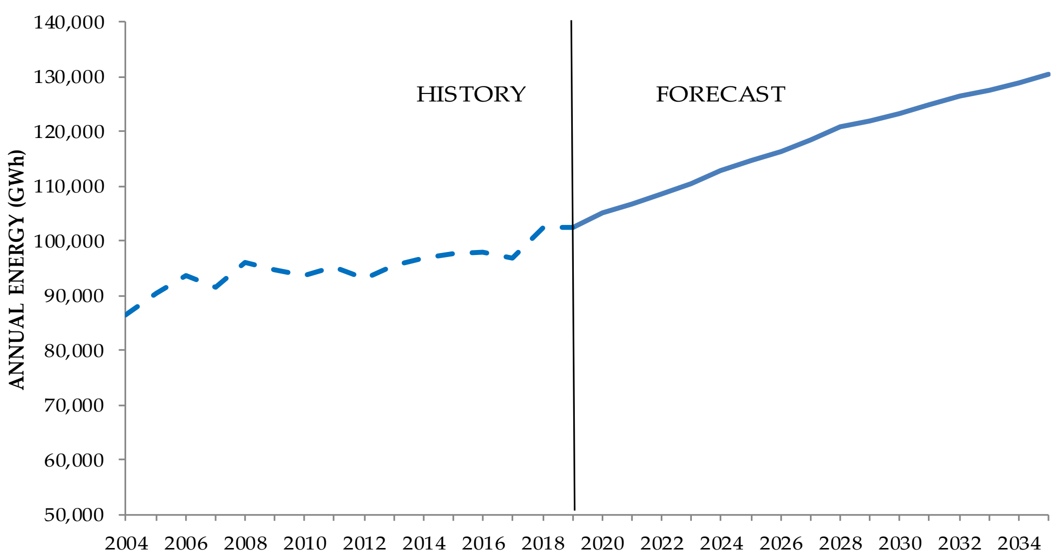


Figure 4.1.2.9 – DOM Zone Annual Energy Based on Company Load Forecast



4.1.3 Energy Efficiency Adjustment

The load forecasts in this 2020 Plan include a downward post-model adjustment for energy efficiency ("EE"). The EE adjustment to the forecasts can be broken down into two distinct categories. The first category ("Category 1 Programs") consists of previously-approved EE programs that remain effective, along with programs that are currently pending approval before the SCC in Case No. PUR-2019-00201. The second category ("Category 2 Program") is a "generic" EE program that is designed to meet the requirements of the: (i) VCEA; and (ii) GTSA. Specifically, the Category 2 Program was designed to increase the level of EE to meet the 2022 through 2025 EE targets set in the VCEA and to meet the GTSA requirement to propose $870 million in EE programs by 2028. Alternative Plan A includes only adjustment for Category 1 Programs. Alternative Plans B through D include adjustment for both Category 1 and Category 2 Programs.

To estimate the Category 2 Program, the Company first determined the projected 2028 EE savings and EE costs associated with the Category 1 Programs. Using this information, the Company then determined the added EE savings necessary to meet the EE targets of the VCEA and also the EE savings needed to achieve the $870 million in EE-related spending by 2028. The Category 2 Program volumes were determined assuming a generic EE program fixed price of $200/MWh, which is based on the Company's 2018 solicitation to vendors. This approach is a theoretical assumption used for planning purposes only. In reality, the level of energy efficiency savings included in this 2020 Plan may not materialize in the same manner as modeled due to many outside factors. These factors could include but are not limited to the ability of future vendors to deliver program savings at the fixed price, the desire of customers to participate in the program at that price, and the effectiveness of the program to be administered at that price. Therefore, the costs and level of savings modeled for the Category 2 Program are placeholders that will be revised as future phases of actual EE programs are developed and implemented.

The Category 2 Program forecast uses a start date of January 1, 2021, and grows at a pace that will meet the 2022, 2023, 2024, and 2025 EE targets required in the VCEA. The Program continues to grow until the total EE spend equates to $870 million in 2028. After 2028, the Category 2 Program levels out for a five-year period, and then begins a slow downward trajectory that simulates a loss in program participation. Figures 4.1.3.1 and 4.1.3.2 identify the EE energy and capacity adjustments to the load forecasts used in this 2020 Plan. As stated, Alternative Plan A includes only adjustment for Category 1 Programs, while Alternative Plans B through D include adjustment for both Category 1 and Category 2 Programs.

Figure 4.1.3.1 – EE Energy Forecast

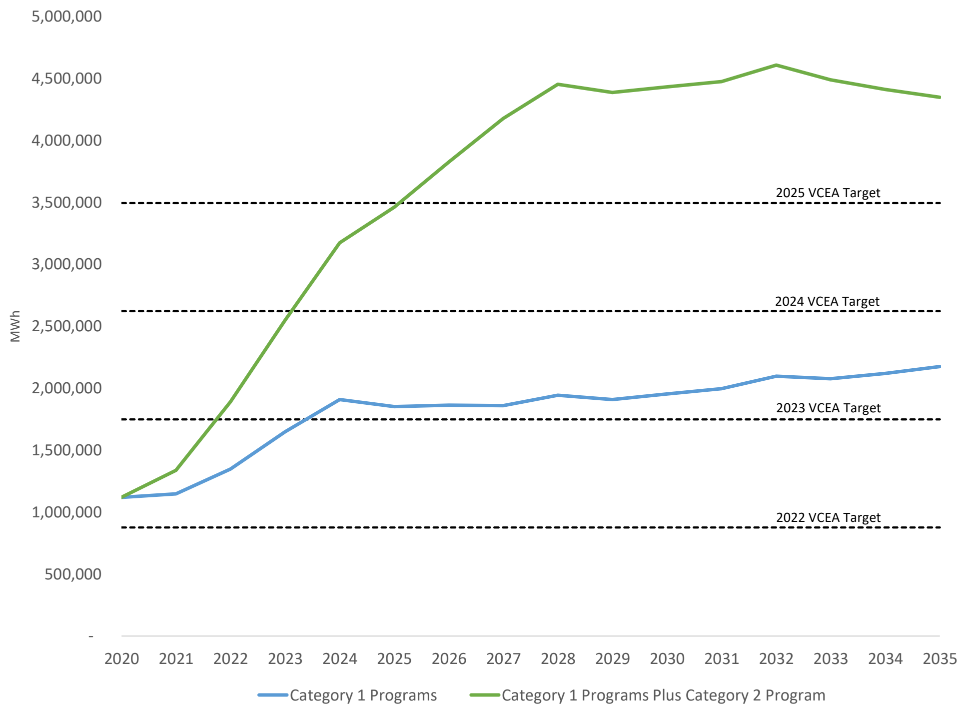
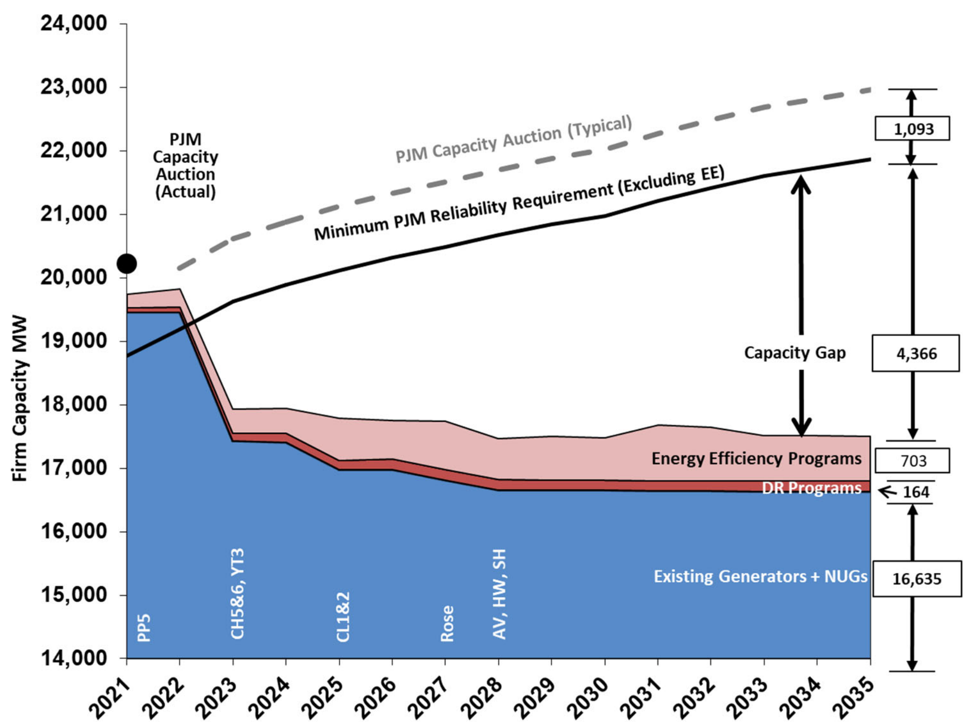


Figure 4.1.3.2 – EE Coincident Summer Peak Demand Forecast

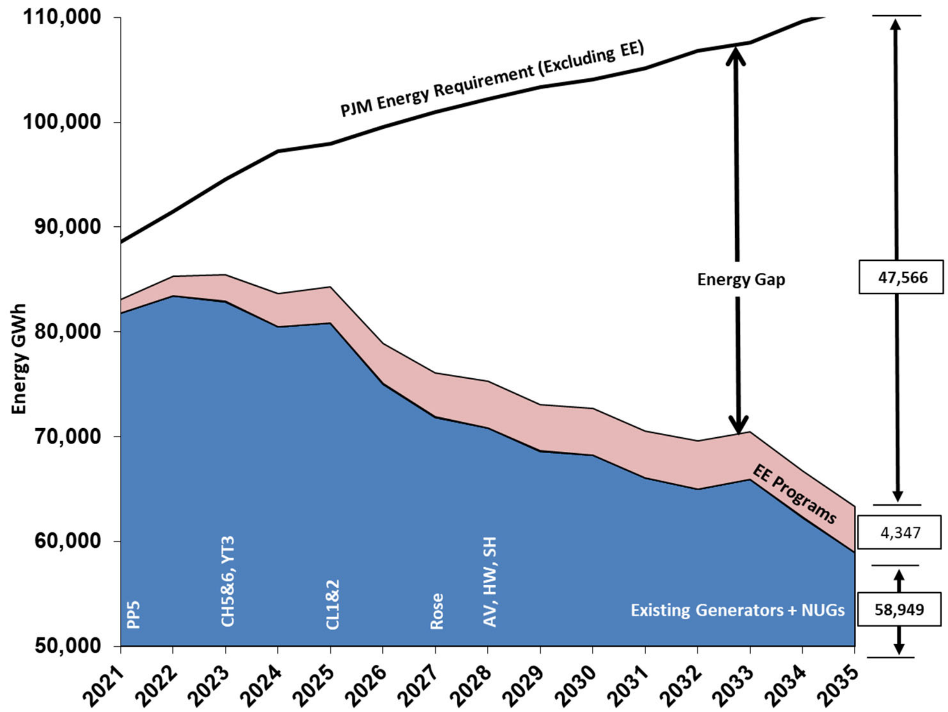
The Company also modeled EE as a supply-side resource in the PLEXOS model. The modeling of EE as a load reducer and as a supply-side resource resulted in effectively identical results. Figures 4.1.3.3 and 4.1.3.4 show the Company's current capacity and energy position with DSM modeled as a supply-side resource using unit retirement assumptions for Alternative Plan B.

Figure 4.1.3.3 - Current Company Capacity Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 4.1.3.4 - Current Company Energy Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

4.1.4 Retail Choice Adjustment

The load forecasts in this 2020 Plan include a downward post-modeling adjustment for customers within the Company's service territory who have chosen (or may choose) to purchase energy and capacity from third-party retail electric suppliers under Va. Code § 56-577 ("Choice Customers"). To develop this forecast the Company first determined the number of current and potential Choice Customers for 2019 and 2020. This included those customers eligible to participate in the pilot program established by House Bill No. 889 in the 2020 Regular Session of the Virginia General Assembly for up to 200 MW of non-residential load to aggregate and purchase electricity from third-party suppliers. Based on this total set of customers, the Company then determined the average energy and peak demand for each of these customers over the last three years.

The summation of each customer's average annual energy and capacity use then formed the starting point for the Choice Customer forecast. This Choice Customer starting point is composed of two different types of customers. The first set is customers that have pursued, or may pursue, third-party supply under Va. Code § 56-577 A 3 or A 4 ("A 3 and A 4 Choice Customers"), while the second set is made up of customers that have opted, or may opt, for third-party supply under Va. Code § 56-577 A 5 ("A 5 Choice Customers"). Given that A 3 and A 4

Choice Customers must provide five years' advanced written notice before returning to purchase electricity from the Company, the Company assumed in this forecast adjustment that those customers would remain under third-party supply for the entire Study Period. To the extent A 3 and A 4 Choice Customers file written notice to return to Company service, the Company can factor this load into its future load forecast adjustments. Given that A 5 Choice Customers have no similar advance written notice requirement, the Company must remain cognizant that those customers could return to Company service at any time and must plan accordingly as the default service provider. In addition, A 5 Choice Customers will no longer be able to purchase electricity from third-party suppliers if the SCC approves the Company's proposed Rider TRG pending in Case No. PUR-2019-00094. Therefore, the Company assumed in this forecast that A 5 Choice Customers gradually return to full Company service by the end of 2023. Figures 4.1.4.1 and 4.1.4.2 identify the Choice Customer peak demand and energy forecast adjustment in this 2020 Plan.

Figure 4.1.4.1 – Choice Customer Energy Forecast

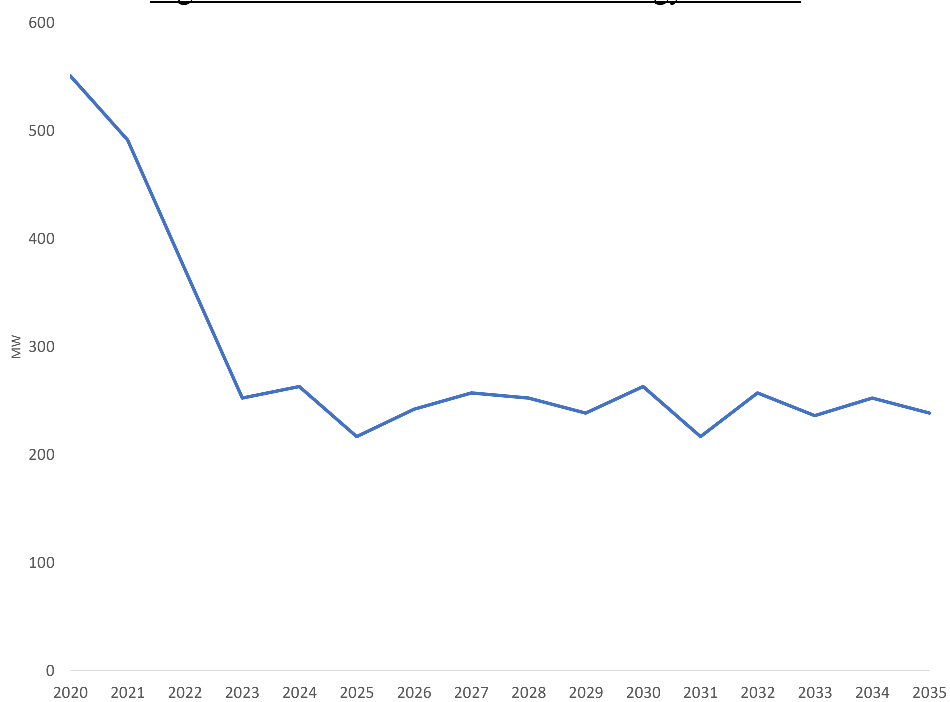
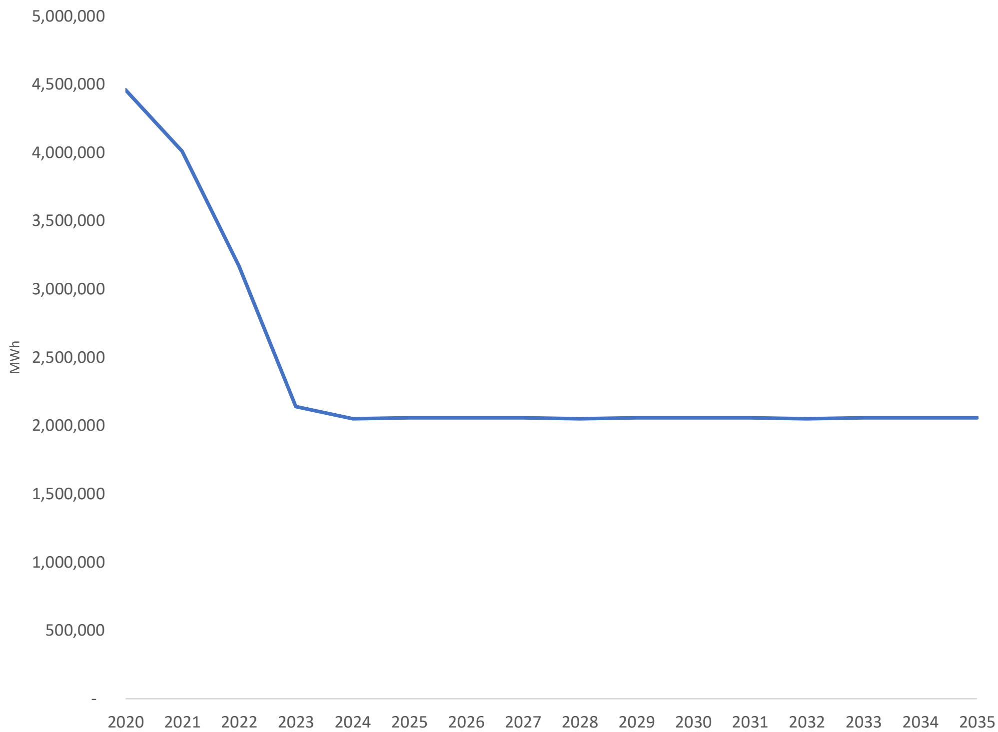


Figure 4.1.4.2 – Choice Customer Coincident Summer Peak Demand Forecast



4.1.5 Voltage Optimization Adjustment

As part of its Grid Transformation Plan, discussed further in Section 8.3, the Company seeks to fully deploy AMI across its service territory, and then use this technology to enable voltage optimization. Voltage optimization, if approved and deployed, would lead to energy and capacity savings. Because of the preparation schedule associated with this 2020 Plan, Alternative Plans B, C, and D include a post-model downward adjustment to the load forecast to account for the savings associated with voltage optimization as proposed in the Grid Transformation Plan. Figures 4.1.5.1 and 4.1.5.2 reflect the peak demand and energy savings forecast adjustment resulting from voltage optimization.

Figure 4.1.5.1 – Voltage Optimization Coincident Summer Peak Demand Forecast

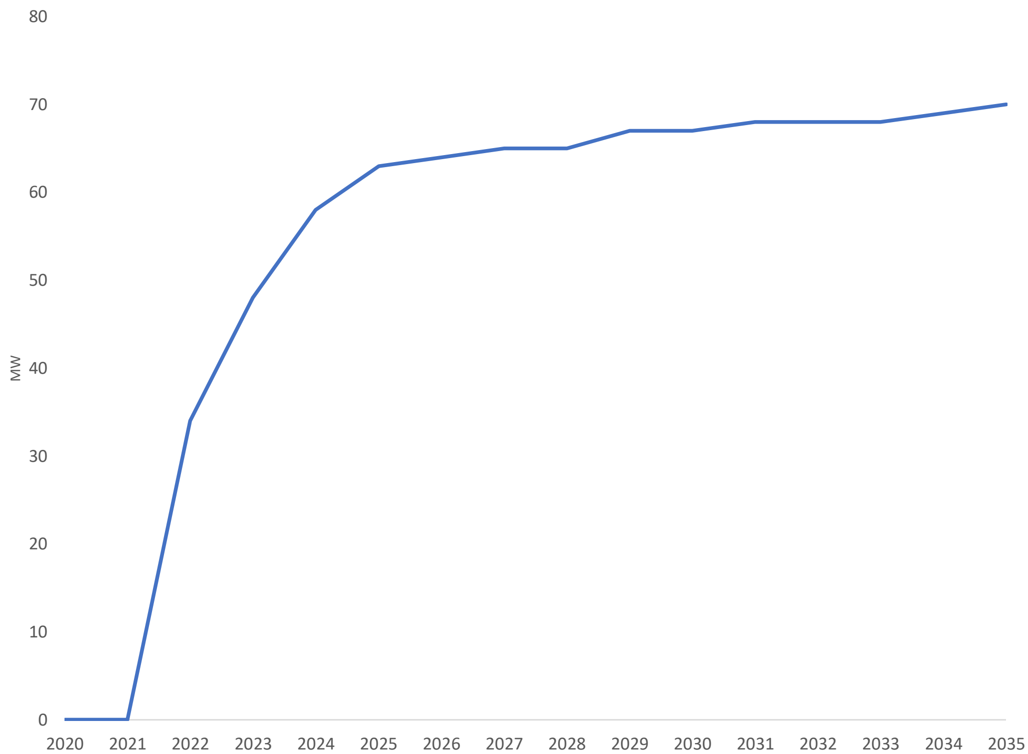
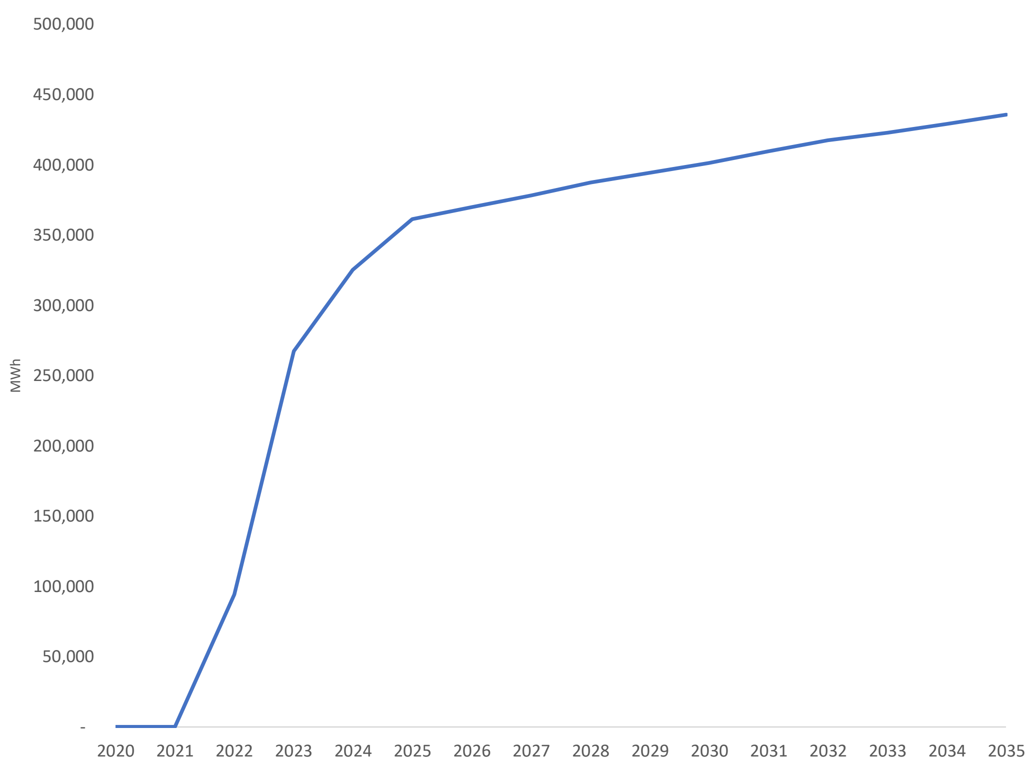


Figure 4.1.5.2 – Voltage Optimization Energy Forecast



4.2 Capacity Market Assumptions

The Company participates in the PJM capacity planning process to ensure supply of capacity resources for its customer load. As a member of PJM, the Company has the option to buy capacity in order to satisfy the mandated reliability requirements either (i) through the RPM forward capacity market or (ii) through the FRR alternative. PJM's planning years (referred to as "delivery years" for RPM) run from June 1 to May 31. The Company has satisfied its capacity obligation through the RPM auction through May 31, 2022.

Short-Term Capacity Planning

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to purchase sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone using its annual load forecast and reserve margin guidelines as inputs. PJM then conducts a capacity auction process for meeting these input requirements up to three years into the future. This auction process includes the base RPM auction as well as and subsequent incremental auctions that are held to allow market sellers and PJM to adjust positions for changes such as construction delays or outage assumptions. This auction process determines the clearing reserve margin and the capacity price for each zone for the delivery year that is three years in the future (*e.g.*, the 2018 base RPM auction procured capacity for the delivery year 2021/2022).

PJM has delayed the 2019 and 2020 auction processes due to the pending FERC MOPR proceeding discussed in Section 1.6.1. Following resolution of this proceeding, PJM plans to compress the timelines for these auctions, currently targeting late 2020 or early 2021 for resuming the RPM auction process.

Currently, the Company offers its capacity resources, including owned and contracted generation, into the RPM auction as a generation provider. As an LSE, the Company is then obligated to purchase capacity to cover its PJM auction-determined capacity requirements.

In the future, the Company could satisfy its capacity obligation through the FRR alternative. As discussed in Section 1.6.2, this alternative would allow the Company to self-supply its capacity obligation. Importantly for modeling purposes, however, the modeling is indifferent to whether the Company satisfies its capacity obligation through the RPM auction or through the FRR alternative. Operating under the FRR alternative, the Company would self-supply its capacity obligation. Instead of collecting a capacity revenue stream for generating resources, the Company assumes generating resources would obtain capacity benefit by *avoiding* capacity market purchases. For modeling purposes, the Company would continue to use capacity market forecasts and assume generating resources collect capacity benefits by avoiding capacity purchases under FRR. Further, the modeling is indifferent to whether the Company operates under the FRR alternative because the Company models the forecasted reserve margin at the minimum reserve margin, which is also the obligation under FRR. Figure 2.1.1 indicates both the minimum PJM reserve requirement (*i.e.*, the solid line) and the typical market reserve requirement (*i.e.*, the dashed line).

Long-Term Capacity Planning – Reserve Requirements

The Company uses PJM's reserve margin guidelines 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 as a loss of load expectation equivalent to one day of outage in ten years. To satisfy the NERC and Reliability First Corporation Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation, PJM's 2019 Reserve Requirement Study recommended using an installed reserve margin of 15.9% for delivery year 2020/2021, 15.1% for delivery year 2021/2022, 14.9% for delivery year 2022/2023, and 14.8% for delivery year 2023/2024.

PJM develops reserve margin estimates for planning years rather than calendar years. Because PJM is a summer peaking entity, and because 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 PJM's 2020/2021 delivery year assumptions for the 2020 calendar year in this 2020 Plan because it represents the expected peak load during the summer of 2020.

The Company makes one assumption when applying the PJM reserve margin to the Company's modeling efforts. Since PJM uses a shorter planning period than the Company (*i.e.*, ten years for PJM rather than 15 years for the Company), the Company uses the most recent PJM Reserve Requirements Study and assumes the reserve margin value for delivery year 2023 would continue throughout the Study Period. Figure 4.2.1 shows the adjusted load forecast used in the modeling of Alternative Plans B, C, and D.

Figure 4.2.1 – PJM Adjusted Load Forecast

Year	PJM DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM LSE Adjustments[1] (MW)	PJM Reserve Requirement (%)	DOM LSE Reserve Requirement (MW)	Total DOM LSE Peak Requirement (MW)
2021	19,486	16,802	705	15.1 %	2,431	18,528
2022	19,837	17,105	693	14.9 %	2,445	18,857
2023	20,178	17,339	683	14.8 %	2,474	19,190
2024	20,462	17,644	723	14.8 %	2,504	19,425
2025	20,651	17,807	944	14.8 %	2,496	19,359
2026	20,880	18,004	915	14.8 %	2,529	19,618
2027	21,072	18,170	1,083	14.8 %	2,529	19,616
2028	21,250	18,323	962	14.8 %	2,569	19,931
2029	21,404	18,456	992	14.8 %	2,585	20,048
2030	21,572	18,601	998	14.8 %	2,605	20,208
2031	21,756	18,759	1,156	14.8 %	2,605	20,208
2032	22,008	18,977	1,163	14.8 %	2,636	20,450
2033	22,176	19,121	1,022	14.8 %	2,679	20,779
2034	22,326	19,251	1,030	14.8 %	2,697	20,917
2035	22,249	19,357	1,011	14.8 %	2,715	21,061

Notes: (1) "DOM LSE Adjustments" include adjustments to the load forecast for energy efficiency, retail choice, and voltage optimization as discussed in Sections 4.1.3, 4.1.4, and 4.1.5, respectively.

As discussed in Section 1.6.2, the Company has historically purchased reserves in excess of the approximately 15% planning reserve margin. Given this history, Figure 2.1.1, as well as the capacity figures in Appendix 2A, display a second capacity requirement labeled "PJM Capacity Auction (Typical)" that includes an additional 5% reserve requirement target that is commensurate with the upper bound where the RPM market has historically cleared. All Alternative Plans were optimized to meet the PJM coincident summer peak load forecast as discussed in Section 4.1.1, which is labeled as "Minimum PJM Reliability Requirement (Net of EE)" in Figure 2.1.1, as well as the capacity figures in Appendix 2A.

Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annual updates to load and reserve requirements. Appendix 4H provides a summary of PJM's summer and winter peak load and energy forecast, while Appendix 4I provides a summary of projected PJM reserve margins for summer peak demand.

4.3 Capacity Value Assumptions

Since the fall of 2018, PJM has been developing a probabilistic analysis aimed at valuing the capacity value of renewable resources. This approach utilizes a concept called effective load carrying capability ("ELCC"). As defined by PJM, ELCC is a measure of the additional load that the system can supply with the particular generator of interest without a change in reliability. ELCC can also be defined as the equivalent MW of a traditional generator that results in the same reliability outcome based on what a particular generator of interest (such as an intermittent generator) can provide. The metric of reliability used by PJM is loss of load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value (*i.e.*, a higher ELCC) than a resource that delivers the same capacity only during low-risk hours. "High-risk hours" are those hours that PJM expects the peak demand to occur.

For the purposes of the 2020 Plan, the Company has used the PJM ELCC studies published to date to estimate the capacity value of solar resources. This approach indicated the capacity value of solar is currently in the 45% range, but decreases over time as the solar saturation grows. PJM currently performs its load forecasts, installed reserve margins, reliability metrics, and ELCC calculations at the hourly or daily level.

The Company has assumed approximately 30% capacity value for offshore wind. This capacity value is based on the PJM-approved capacity value associated with the Company's proposed offshore wind queue projects because, to date, PJM has not published an ELCC-based analysis for offshore wind.

For storage resources, PJM currently adheres to a 10-hour run requirement for determining capacity value. This rule dictates that for capacity market participation, a storage resource with duration less than 10 hours will be de-rated down to the capacity value equal to the resource's duration as a fraction of 10 hours. This rule is currently under review by FERC. PJM has also recently initiated an effort to develop ELCC calculations for storage resources. The storage approach would likely incorporate the dispatch characteristics and duration of storage resources. Because of these pending initiatives, the Company has modeled the capacity value of storage resources using PJM's existing 10-hour requirement for the purposes of the 2020 Plan.

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 analyses in this 2020 Plan using energy and commodity price forecasts provided by ICF Resources, LLC ("ICF") in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, power, emissions (SO_x, NO_x) and renewable energy certificate ("REC") prices rely on forward market prices as of December 31, 2019, for the first 18 months of the Study Period 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 and CO_2 prices are provided by ICF for all years forecasted within this 2020 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM base residual auction through the 2021/2022 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2022/2023 delivery year.

In the 2020 Plan, the Company utilized four commodity forecasts:

- No CO_2 Tax
- Mid-Case Federal CO_2 with Virginia in RGGI

- Virginia in RGGI
- High-Case Federal CO_2

Appendix 4O provides the annual prices for each commodity forecast.

These commodity forecasts approached carbon scenarios using various potential outcomes to regulations or legislation designed to reduce CO_2 emissions. The Virginia in RGGI commodity forecast addressed RGGI on a standalone basis. To address the potential for more stringent regulation or legislation at the federal level, the High-Case Federal CO_2 commodity forecast was developed. The combined impact of RGGI and more moderate federal CO_2 regulation or legislation is addressed in the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast.

The Company utilized the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast for Alternative Plans B through D, and the No CO_2 Tax commodity forecast in Plan A. The Company ran sensitivities on Alternative Plan B, keeping the same build plan, but then applying the Virginia in RGGI commodity forecast and, separately, the High-Case Federal CO_2 commodity forecast. The intent of these sensitivities is to show the effect on NPV using a range of commodity prices. Figure 4.4.1 displays the results of these sensitivities.

Figure 4.4.1 – Commodity Forecast Sensitivity

	Plan B	**Plan B Commodity Forecast Sensitivity 1**	**Plan B Commodity Forecast Sensitivity 2**
Load Forecast	Mid-Case Federal CO_2	Virginia in RGGI	High-Case Federal CO_2
NPV Total	$66.2 B	$65.7 B	$67.6 B

As can be seen, using the High-Case Federal CO_2 commodity forecast results in a higher NPV because of higher CO_2 prices, all other Plan B assumptions being equal. The sensitivity using the Virginia in RGGI commodity forecast results in a similar NPV as Alternative Plan B because of the similarities in pricing between these two forecasts.

Because of the preparation schedule associated with this 2020 Plan, the commodity price forecasts do not include the regional impacts on commodity prices that may result from the VCEA. As with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this 2020 Plan. History has shown that unforeseen events and events not contemplated five or ten years before their occurrence can result in significant changes in market fundamentals. The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in the 2020 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes.

4.4.1 Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast

The Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast was developed for the Company to address a future market environment where both regional and federal carbon regulations affect electric generation units. The Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast reflects both (i) Virginia being a full member of RGGI in 2021 and (ii) a federal carbon program. The federal carbon program assumed in this forecast is driven by regulations reflecting a federal policy consistent with the goals identified under the last iteration of the federal Clean Power Plan ("CPP"). ICF recalculated the CPP mass caps to reflect the changes in emission levels since the EPA first determined the CPP state budgets. While it is likely that future regulation would include different requirements than the CPP, ICF relied on the requirements of this representative "mid" case for future CO_2 regulations of the power sector. This representation assumes that states adopt mass-based standards within a national trading structure covering all states, except California which maintains a state-specific program. It also assumes that existing and new sources are included under the cap-and-trade program; RGGI and the California-specific programs continue as individual programs. This type of CO_2 program is assumed to begin in 2026 because it would not require legislative action at the federal level.

Utilizing the Mid-Case Federal CO_2 with RGGI in Virginia commodity forecast allows the Company to evaluate Alternative Plans using a commodity price forecast that reflects ICF's independent view of future market conditions with Virginia being a full participant in RGGI and modest regulations on carbon emissions from electric generation activities at the federal level. ICF's independent, internal views of key market drivers include: (i) market structure and policy elements that shape allowance markets; (ii) fuel and power market fundamentals ranging from expected capacity and pollution control installations; (iii) environmental regulations; and (iv) fuel supply-side issues. The development process assesses the effect of environmental regulations on the power and fuel markets and incorporates ICF's views on the outcome of new regulatory initiatives.

Figure 4.4.1.1 presents a comparison of average fuel, power, and REC prices used in the 2018 Plan and the 2019 update to the 2018 Plan (the "2019 Update") relative to those used in this 2020 Plan. See Appendix 4P for additional details of these forecasts, including fuel, allowance, power price forecasts, and the PJM RTO capacity price forecast. See Appendix 4R for delivered fuel prices and primary fuel expense from the PLEXOS model output using the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast.

Figure 4.4.1.1 –Fuel, Power, and REC Price Commodity Forecast Comparison

	Planning Period Comparison Average Value (Nominal $)		
Fuel Price	2018 Plan Federal CO_2 [3]	2019 Update Virginia in RGGI [3]	2020 Plan Mid-Case Federal CO_2 with Virginia in RGGI [3]
Henry Hub Natural Gas[1] ($/MMbtu)	4.29	3.81	4.05
Zone 5 Delivered Natural Gas[1] ($/MMbtu)	3.71	3.54	3.68
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.66	2.42	2.97
No. 2 Oil ($/MMbtu)	18.52	17.78	17.89
1% No. 6 Oil ($/MMbtu)	11.93	11.56	11.52
Electric and REC Prices			
PJM-DOM On-Peak ($/MWh)	41.29	38.94	44.58
PJM-DOM Off-Peak ($/MWh)	34.36	32.79	34.78
PJM Tier 1 REC Prices[4] ($/MWh)	5.73	6.72	9.13
RTO Capacity Prices[2] ($/KW-yr)	59.33	62.50	57.34

Notes: 1) Zone 5 natural gas price used in Plan analyses. Henry Hub prices shown to provide market reference.
2) Capacity price represents actual clearing price from the PJM RPM base residual auction through delivery year 2020/2021 for 2018 Plan, and through delivery year 2021/2022 for the 2020 Plan and 2019 Update.
3) 2018 Planning Period 2019-2033, 2019 Planning Period 2020-2034, 2020 Planning Period 2021-2035.
4) The 2018 Plan column reflects the PJM Tier 1 REC prices as filed in the 2018 Compliance Filing.

4.4.2 No CO_2 Tax Commodity Forecast

The No CO_2 Tax commodity forecast anticipates a future without any new regulations or restrictions on CO_2 emissions beyond those already in place or previously approved. DOM Zone peak energy prices are slightly lower than the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast across the Planning Period because there is no incremental requirement to comply with CO_2 regulation targets to pass through to power prices. Given forthcoming law in Virginia imposing CO_2 regulation, this assumption is, in the Company's view, no longer reasonable. The No CO_2 Tax forecast is utilized only in analysis of Alternative Plan A, which is presented solely to measure additional costs of various planning scenarios.

4.4.3 Virginia in RGGI Commodity Forecast

The Virginia in RGGI commodity forecast includes New Jersey and Virginia as new participants in RGGI (Virginia in 2021), along with the nine existing RGGI states. The key assumptions regarding market structure and the use of an integrated, internally-consistent fundamental based modeling methodology remain consistent with those utilized in the other commodity forecast except that the carbon program modeled is RGGI and that there is no federal program addressing CO_2 reduction targets.

RGGI utilizes an emissions containment reserve ("ECR") as a trigger to limit downward pressure on the CO_2 allowance price. The ECR price trigger starts at $6 in 2021 and increases at 7% annually. If triggered, the ECR withholds up to 10% of the auction budget of states opting to implement the ECR (the ECR is modeled for all states but Maine and New Hampshire). In the

Virginia in RGGI commodity forecast, the RGGI prices are forecasted to be below the ECR trigger price and, therefore, in ICF's model the emission budget (cap) is reduced by 10% in the years it is triggered. Even with the 10% reduction in allowances, the market clearing prices remain below the ECR trigger prices. The reason for the lower clearing prices is that the CO_2 allowance supply in this case is driven not by coal generation displacement, but by the state policies (in member states) that continue to drive non-fossil generation growth. Carbon reductions are being driven by the high RPS targets in many of the RGGI states, with several states targeting 50% renewable or clean energy standards by the 2030 to 2035 timeframe, and further increasing beyond those years. Additionally, offshore wind procurements are modeled in 7 of the 11 RGGI states (*i.e.*, RI, VA, CT, MA, MD, NJ, NY), providing added clean energy in the RGGI region and displacing fossil resources. As noted earlier, the Virginia in RGGI commodity forecast does not include the regional effects of VCEA on RGGI allowance prices; therefore, the forecast does not account for the additional carbon reductions associated with the revised RPS requirements in Virginia.

4.4.4 High-Case Federal CO_2 Commodity Forecast

The High-Case Federal CO_2 commodity forecast addresses a scenario with a more stringent CO_2 regulatory environment implemented nationwide. In this commodity forecast, CO_2 regulation is addressed as a legislative approach to a national mass cap-and-trade program that begins in 2028 and targets an approximately 80% reduction from 2005 sector emissions by 2050. This target is similar to CO_2 reduction levels being discussed by several states, and it is consistent with what was proposed under the Waxman-Markey Bill in 2009. Load under this scenario increases relative to the other cases because of state electrification efforts. The tightening carbon cap and higher load compared to the No CO_2 Tax commodity forecast leads to higher renewable buildout and lower nuclear retirements. The "high" case includes existing and new sources under a national cap and trade program. This representation assumes that all states participate in the program except for California, which maintains its state-specific program. In this commodity forecast, ICF assumed that Virginia does not join RGGI. Compared to the Mid Case Federal CO_2 with RGGI in Virginia commodity forecast, the power prices are lower in the near term, while post-2025 all hours prices are roughly 36% higher on average. The higher power price is driven by CO_2 allowance price in excess of $100/ton by 2050.

4.4.5 Capacity Price Forecasting Methodology

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and
- Ancillary Services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of supply- and demand-side resources needed to meet predicted peak demand in the future. In a capacity market, utilities or other electricity suppliers are required to purchase adequate resources to meet their customers' demand plus a reserve amount. Suppliers offer supply- or demand-side resources into the capacity market at a price. To the extent the supply offer clears the market, then those capacity resources are obligated to supply energy (or reduce energy in the case of demand-side resources) when dispatched, or pay penalty fees.

The RPM is designed to provide financial incentives to attract and maintain sufficient capacity to meet the load demands anticipated by PJM; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. Parallel to the actual market construct, forecasting of long-term capacity prices is based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market energy and ancillary services revenue is not sufficient, then capacity revenues are required to fill this gap.

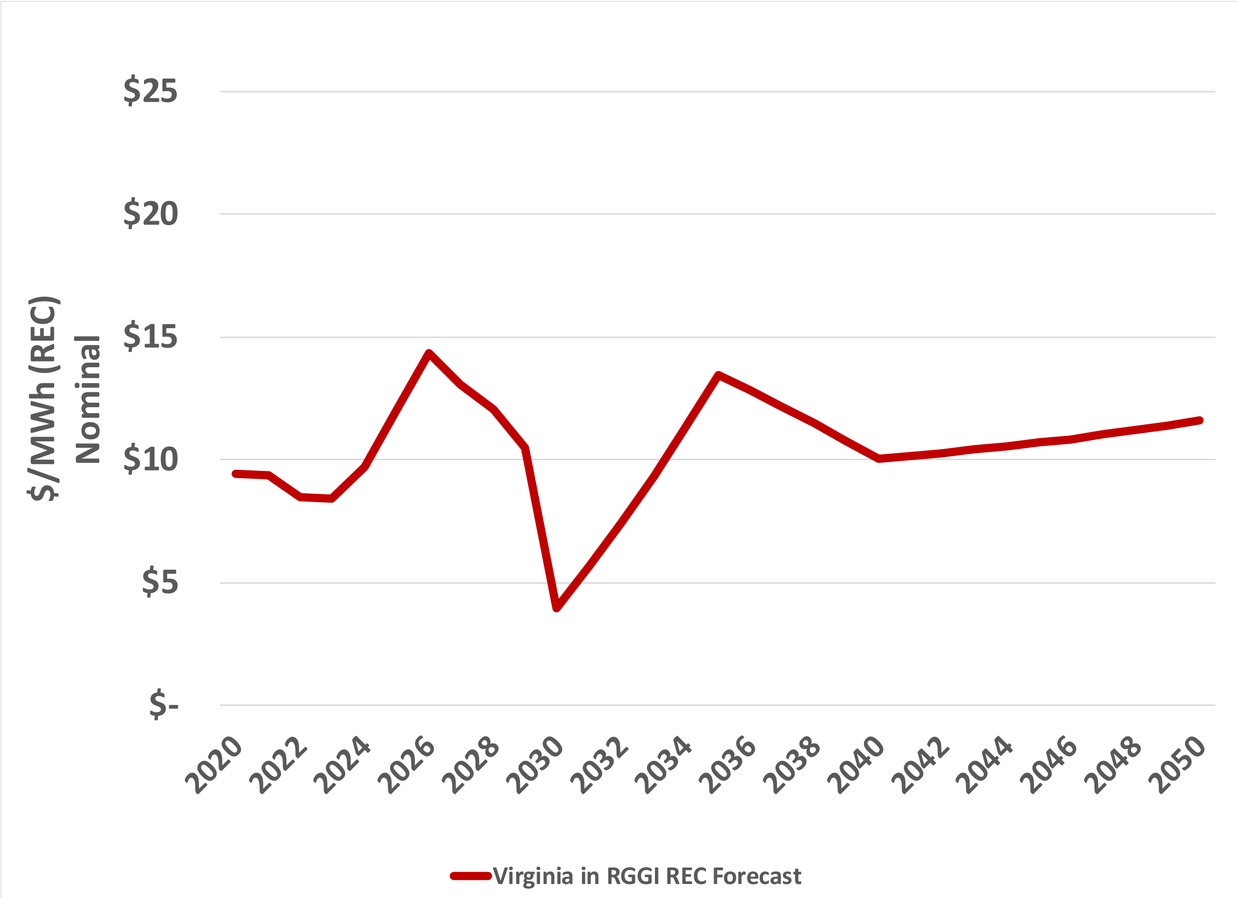
When forecasting capacity prices over long periods, it is reasonable to assume markets will move toward equilibrium and will provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the new resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower in markets with excess capacity. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note that while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up-and-down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

For these reasons, the issues surrounding the FERC MOPR Order described is Section 1.6.1 do not change the methods used to develop long-term capacity price forecasts.

4.4.6 REC Price Forecasting Methodology

Together with ICF, the Company developed a revised methodology for forecasting REC Tier 1 prices from what was presented in the 2018 Plan. A white paper describing the forecasting methodology and providing details related to the revised methodology for forecasting REC prices is provided in Appendix 4Q. The white paper also includes a section that illustrates the impact on REC prices if the federal tax credits for production tax credits and investment tax credits are extended indefinitely. Figure 4.4.6.1 provides a graph of the REC price forecast for the Virginia in RGGI commodity forecast.

Figure 4.4.6.1 – Tier 1 REC Forecast Comparison



The shape of the REC price forecast illustrated in Figure 4.4.6.1 reflects the fundamental changes occurring in the PJM states' RPS programs and the advancement of state-sponsored offshore wind development. The early price rise forecasted for Tier 1 RECs reflect recently enacted increases in RPS programs in several PJM states. These same states have implemented offshore wind procurement programs designed to supply large amounts of RECs to meet the expanding RPS requirements. The curve through 2030 reflect these fundamental developments, with prices rising as demand for RECs increase with the expanding RPS requirements, but then declining sharply as the large amounts of offshore wind procured by the states provide ample amounts of RECs to meet demand. As noted earlier, these results do not include the regional impacts of the VCEA.

4.5 Virginia Renewable Portfolio Standard Assumptions

In Virginia, the VCEA established a mandatory RPS as discussed in Section 1.2. In this 2020 Plan, the Company optimized the model for each Alternative Plan according to its typical process. The Company then determined whether additional renewable resources were needed to meet the annual RPS requirements, and added additional renewable resources (either Company-build or PPA) as needed. The Company assumed that it could construct or purchase renewable resources at less than the $45/MWh deficiency payment in the VCEA.

4.6 Solar-Related Assumptions

4.6.1 Solar Capacity Factor

For Alternative Plans A and D, the Company modeled future solar resources using a capacity factor of 19%, which is the average capacity factor of the Company's owned solar tracking fleet in the Commonwealth for the most recent three-year period (*i.e.*, 2017, 2018, 2019). For Plans B and C, the Company modeled future solar resources using a design solar capacity factor of 25% based on average modeled output from solar tracking resources.

4.6.2 Solar Company-Build vs. PPA

For solar resources in Alternative Plan A, the Company allowed the model to select either Company-build cost-of-service solar or third-party PPA solar limited at 480 MW per year, which is an assumption on the amount of solar generation available each year. For Alternative Plans B through D, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period. These Alternative Plans exceed the 480 MW per year modeling constraint to meet the requirements of the VCEA.

4.6.3 Solar Interconnection and Integration Costs

The integration of intermittent solar generation into the electric grid involves multiple considerations. Solar generation must first be physically interconnected to the electric grid, either at the transmission or distribution level. The developer of a solar generating facility typically pays the costs to physically interconnect the resource, including any upgrades required near the point of interconnection to assure grid stability. The Company refers to these costs in this 2020 Plan as solar interconnection costs. As increasing volumes of solar generation are interconnected to the grid, additional system-level upgrades must be made by the Company to address grid stability and reliability issues caused by the intermittent nature of these resources. The Company refers to the costs related to these upgrades in this 2020 Plan as solar integration costs. All of these costs are incorporated in the NPV for "Total System Costs" shown in Figure 2.4.1.

In this 2020 Plan, three different categories of solar resources were available in PLEXOS: (i) Company-build solar; (ii) solar PPAs; and (iii) small-scale solar (*i.e.*, less than 3 MW). The Company assumed interconnection cost of $94/kW for Company-build solar and $125.50/kW for small-scale solar. The Company assumed $0 in interconnection costs for solar PPAs because the PPA price from the developer includes interconnection costs.

For solar integration costs, this 2020 Plan includes three categories of system upgrades costs based on different issues caused by the intermittent nature of solar resources:

- **Transmission Integration Costs**: These costs represent physical enhancements to the transmission system needed to resolve low voltage and thermal conditions caused by integrating significant volumes of solar generation. Figure 4.6.3.1 shows the incremental integration costs as solar generation is added to the system.

- **Generation Re-dispatch Costs**: This category represents costs resulting from real-time variability of load and generator availability compared to day-ahead forecasted load and generator availability. The analysis the Company performed resulted in the cost curve shown in Figure 4.6.3.3, which the Company used to add a specific amount per MWh of solar generation by year.
- **Regulating Reserves Costs**: This category represents ancillary payments the Company must make to resources to ensure that the system can balance intra-day or intra-hour differences in load and generation. Figure 4.6.3.4 shows the net cost to customers of regulating reserves included in each Alternative Plan.

The sections below explain the analyses performed for each of these three categories. While the Company has refined its methods to estimate the solar integration costs compared to prior Plans, more analysis is required in order to fully assess the necessary grid modifications and associated costs of integrating increasing amounts of solar generation.

Transmission Integration Costs

The transmission integration costs were assessed by performing a steady state power flow analysis where a total of 7,000 MW of solar generation is present on the transmission grid. Within this analysis, all possible interconnection locations and sizes were selected from the PJM generation interconnection queue to accurately reflect the behaviors of solar developers. Ten different scenarios were considered; the sites that make up the 7,000 MW were a randomly selected subset from the total list of sites from the PJM queue.

Using these ten different solar cases, the PSS®E power flow model were assessed under 2022 PJM light load demand conditions. This analysis included the retirement of certain existing generation units. Additional assumptions included maximum solar generation output (with reactive power support of +/- 0.95 power factor), and displacement of generation from other Company-owned facilities.

The results of these modeling cases identified several low voltage and thermal violations that would require physical enhancements to the Company's transmission system. As noted, this analysis was conducted assuming the addition of 7,000 MW of solar generation. In this 2020 Plan, all Alternative Plans include the addition of significantly more solar generation. Figure 4.6.3.1 shows the incremental integration costs assumed for Company-build solar as additional solar generation is added to the system.

Figure 4.6.3.1 – Total Solar Interconnection and Integration Costs

Solar (COS) MW	Total Cost	Comments
Less than 7,000	$ 94 /kW	Interconnections costs
7,000 – 15,000	$159 /kW	Additional transmission integration costs
15,001 – 25,000	$224 /kW	Additional transmission integration costs
25,001 – 35,000	$289 /kW	Additional transmission integration costs
35,001 – 45,000	$354 /kW	Additional transmission integration costs

Future Plans will expand on this analysis by studying the addition of more significant volumes of solar generation. The Company will also expand this analysis to consider dynamic system conditions and other sensitivity analyses that model sudden fluctuations of solar generation output and the need for other grid services described in Section 7.5.

Generation Re-dispatch Costs

Re-dispatch generation costs are defined in this 2020 Plan as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. Historically, these types of events were driven by load variations due to actual weather that differs from what was forecasted for the period in question. Most power system operators assess the generation needs for a future period, typically the next day, based on load forecasts and commit a series of generators to be available for operation in that period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, however, actual load may vary from what was planned and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional costs due to real time variability are known as re-dispatch costs.

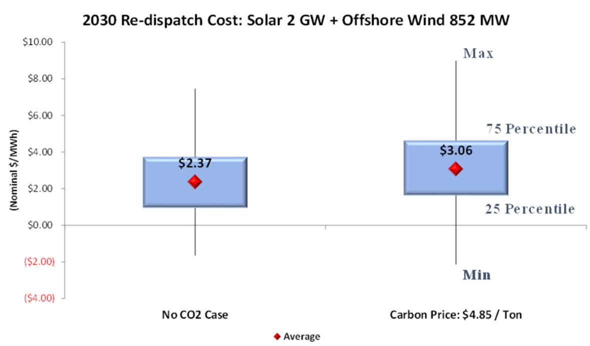
As more intermittent generation—like solar—is added to the grid, additional uncertainty about re-dispatch costs is added due to factors such as unpredictable cloud cover or changes in wind speed. In order to assess the resulting re-dispatch costs, the Company performed a simulation analysis to determine the cost impact on generation operations at varying levels of solar penetration.

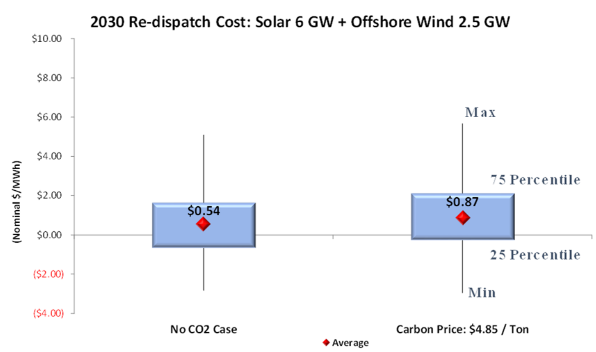
To study the effects of these intermittent resources, the Company first performed a historical 20-year irradiance study (1998 to 2017) of 22 locations within the PJM region plus North Carolina and South Carolina using the National Solar Radiation Database ("NSRDB") provided by the National Renewable Energy Laboratory ("NREL"). Based on the irradiance data in the NSRDB, for each studied location, the Company produced a base hourly solar generation profile along with a set of 200 different hourly solar simulation profiles.

To perform its generation re-dispatch cost analysis, the Company utilized the Aurora planning model with a simulation topology of the Eastern Interconnection. The results from the Aurora model captured not only the DOM Zone hourly prices interactively but also the potential system cost impacts from intermittent resources outside the Company's service territory. This is an improvement over what was provided in the 2018 Plan.

The Company determined scenarios by assuming different levels of the CO_2 prices using assumptions provided by ICF, and two different levels of solar penetration and wind resources by 2030: (i) 2 GW of solar with 852 MW of offshore wind and (ii) 6 GW of solar with 2.5 GW of offshore wind. The renewable penetration level for other states in the Eastern Interconnection was set to a level that met the requirements in the applicable state RPS programs. For each scenario, the Company performed a base case Aurora simulation by using the base hourly solar generation profiles, and performed an additional 200 simulations by using the unit commitment decision determined by the base case and applying different hourly solar simulation profiles from the irradiance study to re-optimized the system cost. The total system cost for each simulation was compared to the base case system cost. This delta system cost is composed of the respective differences in fuel cost, variable O&M cost, emission cost, and purchase/sale cost. The re-dispatch cost is the delta of the system cost divided by the total solar generation. The analysis results are shown in Figure 4.6.3.2.

Figure 4.6.3.2 – Re-Dispatch Analysis Results

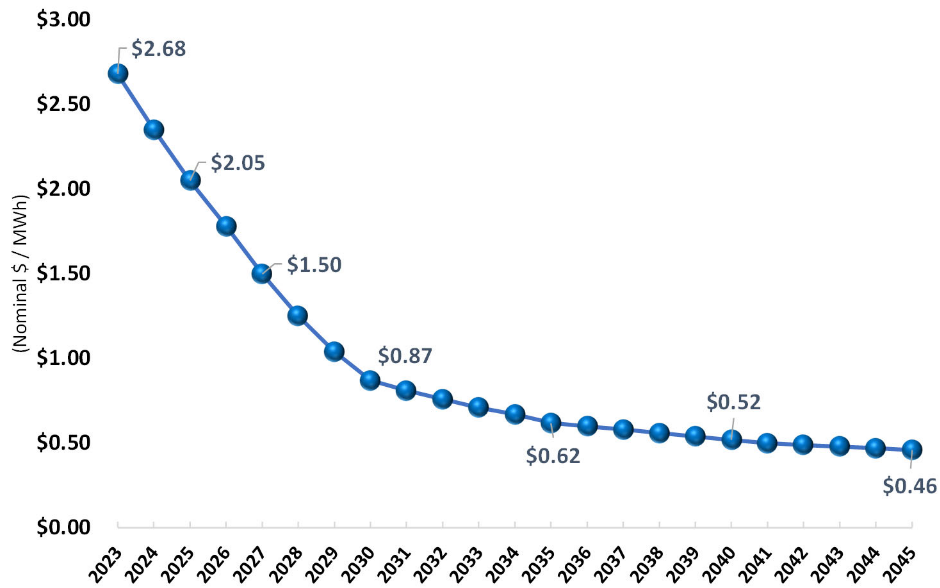




The analysis shows that, under the same level of the solar penetration, higher CO_2 prices result in slightly higher re-dispatch costs along with slightly higher cost volatility. The results also show, however, that as solar penetration increases, the overall re-dispatch costs decrease. This is because higher solar penetration lowers the DOM Zone energy hourly price, which results in lower re-dispatch costs.

Due to the scale of the simulation, the Company only performed the analysis for the study year of 2030. Using this data, the Company constructed a generation re-dispatch cost curve for the Study Period, as shown in Figure 4.6.3.3. These values were used as a variable cost adder for all solar generation evaluated in this 2020 Plan.

Figure 4.6.3.3 - Generation Re-dispatch Cost Results ($/MWh)



Even the 6 GW solar penetration level assessed in this analysis was significantly lower than the volume of solar generation added in all Alternative Plans. In future analyses, the Company will study the addition of more significant volumes of solar generation. The Company will also study the possibilities of incorporating the sensitivities of other intermittent resources, such as onshore and offshore wind generating units within the study footprint.

Regulating Reserve Costs

Regulating reserves are defined in this 2020 Plan as additional reserves needed to balance the uncertainty of forecast errors of net load that occur during a typical power system operational day. These reserves exclude contingency reserves, which are defined as the loss of a major power system generation or transmission system asset. Within the PJM market, these regulating reserves are an ancillary service, the cost of which is charged to customers. Revenues collected for this ancillary service are paid to resources available to supply (or reduce) additional energy to correct forecast errors. Unlike contingency reserves, regulating reserves are needed to either increase (“up reserves”) or decrease (“down reserves”) generation in any given operational hour. These reserves also differ from re-dispatch costs; they are paid to the resource whether they are used or not during the operating hour. The regulating reserve costs ensure that the transmission system has adequate resources available to handle forecast uncertainty. The system pays for regulating reserves so that it has the capability to quickly re-dispatch. In contrast, the operating costs to dispatch these regulating resources (to mitigate forecast errors and stabilize the transmission system) are part of re-dispatch costs.

Historically, the level of regulating reserves was primarily driven by the uncertainty associated with load during any given operating day. The intermittent nature of solar and wind generation adds to this uncertainty. Accordingly, the levels of regulating reserves will need to increase to compensate for this added uncertainty.

A variety of resources can be used to address system uncertainty: energy storage, unscheduled combustion turbine capacity, unscheduled duct burner capacity (on scheduled combined cycle units), intraday purchases and sales, and interruptible load.

In order to assess the increase of regulating reserves that will result from increasing volumes of solar generation, the Company utilized the Electric Power Research Institute ("EPRI") Dynamic Assessment and Determination of Operating Reserves ("DynADOR") tool. This tool calculates operating reserves based on correlations to other variables (*e.g.*, forecasted generation, time of day) and can be used to evaluate solar, wind, and load variations separately and in combination.

For the purposes of this study, the Company used solar data from the Morgan's Corner Solar Facility and wind speed data from Norfolk Airport. The study's timeframe was three years, from April 2016 to March 2019. Norfolk's surface wind speeds were adjusted by a constant wind gradient coefficient to achieve the 42% capacity factor observed in NREL's 2008 to 2012 Wind Tool Kit study of a point located in the Virginia Wind Energy Area. Forecasted wind speeds at 4:00 PM the previous day were used to simulate a day-ahead forecast of wind energy.

Using the solar and wind data described above, the DynADOR tool was set to determine the level of operating reserves needed for 1,000 MW (nameplate) of solar capacity and 1,000 MW (nameplate) of wind capacity each at a 95% confidence interval. This analysis assumed no diversity benefit from the combination of solar and wind, nor any diversity benefits from geography spread. These model results were then applied to the PJM solar and wind renewable expansion plans included in the ICF Virginia in RGGI commodity forecast for each year of the Study Period. This resulted in an hourly level of regulating services needed for each year of the Study Period.

One of the key observations from this study was the benefit during daylight hours of having both solar and wind generation. Because the forecast errors of solar and wind were not highly correlated, the operating reserves were significantly lower in combination than when evaluated independently and added together. This demonstrates the value of having a diverse portfolio of intermittent generation (in addition to the inherent diversity of geographic distribution). Accordingly, the next phase of this study will broaden the impact of increasing renewables generation to assess the benefit of diversity at the PJM level. Solar and wind hourly data from NREL were used to estimate the hourly benefit of technology and geographic diversity throughout PJM. This data was then used to calculate an hourly PJM diversity factor that was multiplied against the combined total of solar and wind hourly regulating reserves, which results in a lower overall hourly regulating reserve volume.

Once the volume of solar and wind (in MW) was determined as described above, the next phase of the analysis was to determine a market price for these reserves. Because of its historical structure that resulted in more definitive regression results, the Company chose the PJM Day-Ahead Secondary Reserves market as a basis to forecast a regulating reserve price. Participation in this market is restricted to dispatchable resources (generation, energy storage, and interruptible load) that are not scheduled in the day-ahead energy market. This market excludes intermittent resources, nuclear, and run-of-river hydro units. The resource must be able to bring the bid energy on the grid within 30 minutes of notification. This market varies in demand and pricing through the year. In 2019, this market averaged $0.39/MW, but hours ranged from $0.00 to over $20.00. Regression was used on these hourly results to shape a relationship between incremental reserves demand (net of incremental reserves supply) and a forecasted market price. This regulating reserve price construct was then applied to the hourly regulating reserve volumes to assess the annual costs of incremental regulating reserves resulting from increased intermittent renewable build within the PJM region.

The results of this analysis reflect the hourly (per MW) cost of regulating reserves gradually increases from $0.61 in 2021 to $20.18 in 2045. This occurs because the rate that PJM is forecasted to increase the need for regulating reserves (driven by the level of renewables build) grows more quickly within PJM than the projected addition of resources that provide regulation reserves in PJM. The forecasts of resource additions (both renewable and regulating resources) is based on ICF projections in states other than Virginia. Virginia resource additions are based on the projections in this 2020 Plan for the Company; for Appalachian Power Company and other sellers of electric power in Virginia, the projections assume solar and wind resource additions according to the RPS requirements for Appalachian Power Company.

From a Company perspective, regulating costs will be incurred when the regulating costs to serve the Company's load exceed the revenue received from PJM for the Company units that supply this ancillary service. Figure 4.6.3.4 shows the net cost to customers included in this 2020 Plan. The Company will continue its analysis of regulating reserves needed for system stability incorporating technological advancements that may mitigate these potential costs, and will present its results in future Plans and update filings.

Figure 4.6.3.4 – Company Net Regulating Reserves Cost of Market Purchases ($000,000)

Year	Plan A	Plan B	Plan C	Plan D
2021	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -
2030	$ -	$ -	$ -	$ -
2031	$ -	$ -	$ -	$ -
2032	$ -	$ -	$ -	$ -
2033	$ -	$ -	$ -	$ -
2034	$ -	$ 72	$ 73	$ 31
2035	$ -	$ 104	$ 105	$ 48
2036	$ -	$ 109	$ 44	$ -
2037	$ -	$ 93	$ -	$ -
2038	$ -	$ 153	$ 69	$ 52
2039	$ -	$ 167	$ 24	$ 28
2040	$ -	$ 247	$ 57	$ 76
2041	$ -	$ 362	$ 145	$ 183
2042	$ -	$ 402	$ 78	$ 137
2043	$ -	$ 502	$ 327	$ 378
2044	$ -	$ 523	$ 357	$ 346
2045	$ -	$ 607	$ 717	$ 827

Note: Zero values indicate that the DOM LSE has adequate regulating reserves to supply reserve requirements from the LSE's load and renewable generation portfolio that year.

4.7 Storage-Related Assumptions

As discussed further in Section 5.5, two types of energy storage resources were available in the PLEXOS model—battery energy storage systems and pumped storage. For BESS, the Company used cost estimates from the request for proposals for the recently-approved BESS pilot at Scott Solar Facility. This BESS is based on a 4-hour discharge configuration. For pumped storage, the Company used preliminary internal cost estimates for a large pump storage facility to be located in southwest Virginia.

In Plans B through D, the Company set constraints requiring the PLEXOS model to select 2,700 MW of energy storage by 2035, consistent with the VCEA, including 300 MW of pumped storage. Third-party owned energy storage will make up 35% of the 2,700 MW. Given the lack of sufficient pricing for storage PPAs, however, the Company did not differentiate between Company-owned and third-party-owned energy storage resources in this 2020 Plan.

4.8 Gas Transportation Cost Assumptions

Natural gas is largely delivered on a just-in-time basis, and vulnerabilities in gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective. Mitigating strategies such as storage, firm fuel contracts, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, and overall fuel diversity all help to alleviate this risk.

There are two types of pipeline transportation service contracts: firm and interruptible. Natural gas provided under a firm service contract is available to the customer at all times during the contract term and is not subject to a prior claim from another customer. For a firm service contract, the customer typically pays a facilities charge representing the customer's share of the capacity construction cost and a fixed monthly capacity reservation charge. Interruptible service contracts provide the customer with natural gas subject to the contractual rights of firm customers. The Company currently uses a combination of both firm and interruptible service to fuel its natural gas-fired generation fleet.

The Company included natural gas transportation costs in its modeling. The Company assumed firm transportation service for CCs and interruptible transportation service for CTs. The Company assumed interruptible transportation service for CTs because these peaking resources typically operate with less than 20% capacity factors and because they are typically equipped with on-site oil backup.

Pipeline deliverability can affect electrical system reliability. A physical disruption to a pipeline or compressor station can interrupt or reduce the flow pressure of gas supply to multiple EGUs at once. Electrical systems also have the ability to adversely affect pipeline reliability. For example, the sudden loss of a large efficient generator can force numerous smaller gas-fired CTs to be started in a short period of time. This sudden change in demand may cause drops in pipeline pressure that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric gas compressor stations, which can disrupt the fuel supply to electric generators.

4.9 Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the PJM Load Forecast adjusted for only existing and proposed energy efficiency as discussed in Section 4.1.3, and uses the No CO_2 Tax commodity forecast as discussed in Section 4.4.2. For Plan A, the Company did not force the model to select any specific resources, and did not exclude any reasonable resource options. The potential unit retirements shown in Plan A are those that are financially at risk for retirement based on market conditions.

4.10 VCEA-Related Assumptions

The Company modeled the requirements and targets contained in the VCEA when it passed the General Assembly on March 5, 2020, as this was the best available information at the time the Company completed its modeling. Virginia Governor Northam signed the VCEA into law without amendment on April 11, 2020. In addition to the VCEA, the Company modeled "other relevant legislation" from the 2020 Regular Session of the Virginia General Assembly (i) related to RGGI as discussed in Section 1.3 and (ii) related to the aggregation pilot as discussed in Section 1.10.

Chapter 5: Generation – Supply-Side Resources

This chapter provides an overview of the Company's existing supply-side generation, the generation resources under construction or development, and the Company's analysis of future supply-side generation. This chapter also provides a discussion of challenges related to the development of significant volumes of solar resources.

5.1 Existing Supply-Side Generation

5.1.1 System Fleet

Figure 5.1.1.1 shows the Company's 2019 capacity resource mix by unit type.

Figure 5.1.1.1 - 2019 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity (MW)	Percentage (%)
Coal	3,684	17.7%
Nuclear	3,348	16.1%
Natural Gas	8,413	40.3%
Pumped Storage	1,808	8.7%
Oil	2,143	10.3%
Renewable	667	3.2%
NUG-Coal	0	0.0%
NUG- Natural Gas Turbine	0	0.0%
NUG- Solar	592	2.8%
NUG- Contracted	198	0.9%
Company Owned	20,063	96.2%
Company Owned and NUG Contracted	20,853	100.0%
Purchases	0	0.0%
Total	20,853	100.0%

Due to differences in operating and fuel costs of various types of units and in PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is dispatched by PJM within PJM's larger footprint, ensuring that customers in the Company's service territory receive the economic benefit of all resources in the PJM power pool regardless of the source. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 5.1.1.2 and 5.1.1.3 provide the Company's 2019 actual capacity and energy mix.

Figure 5.1.1.2 - 2019 Actual Capacity Mix

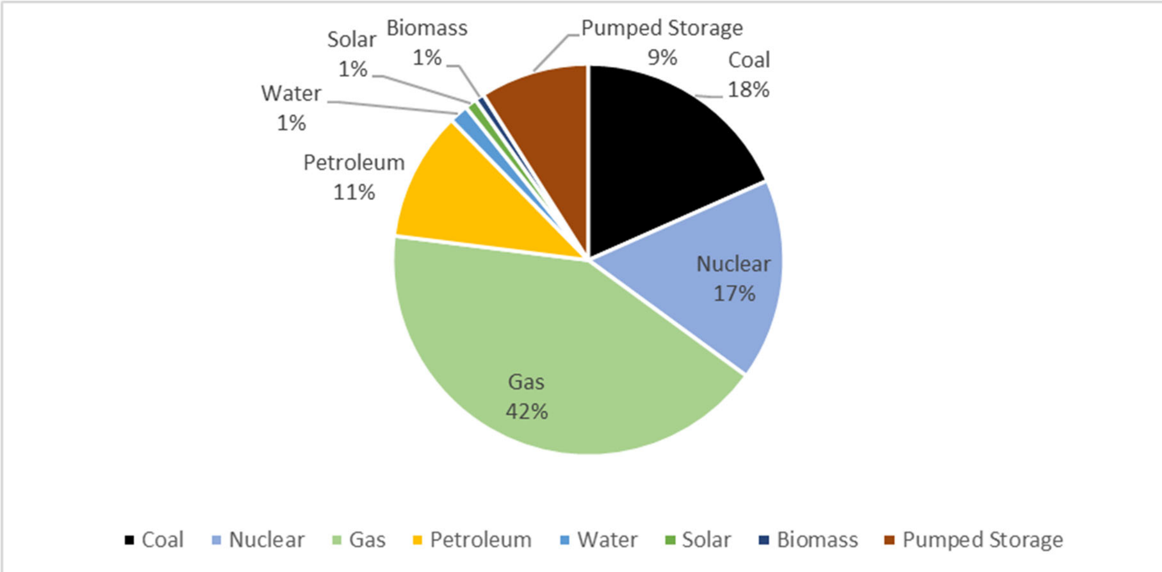
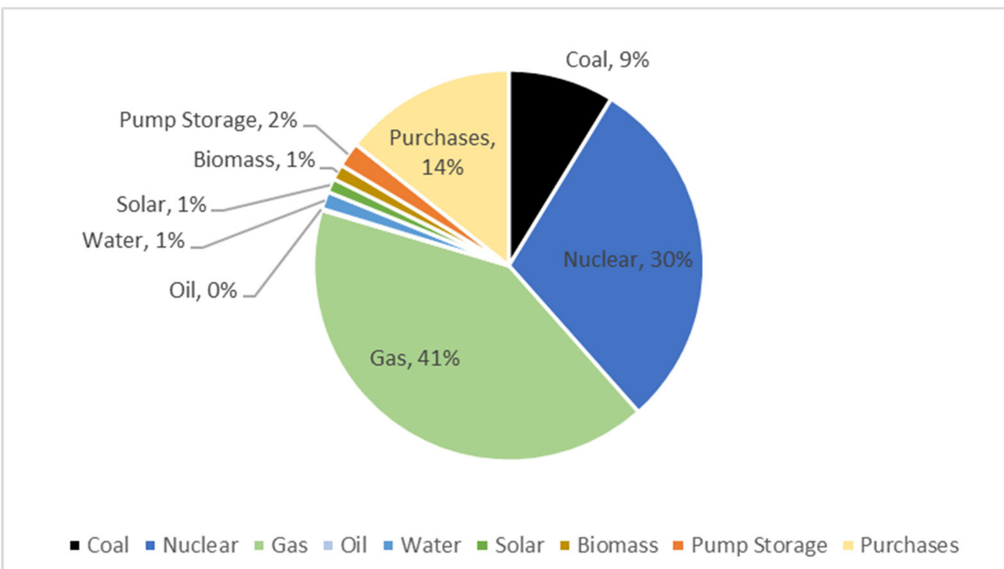


Figure 5.1.1.3 - 2019 Actual Energy Mix

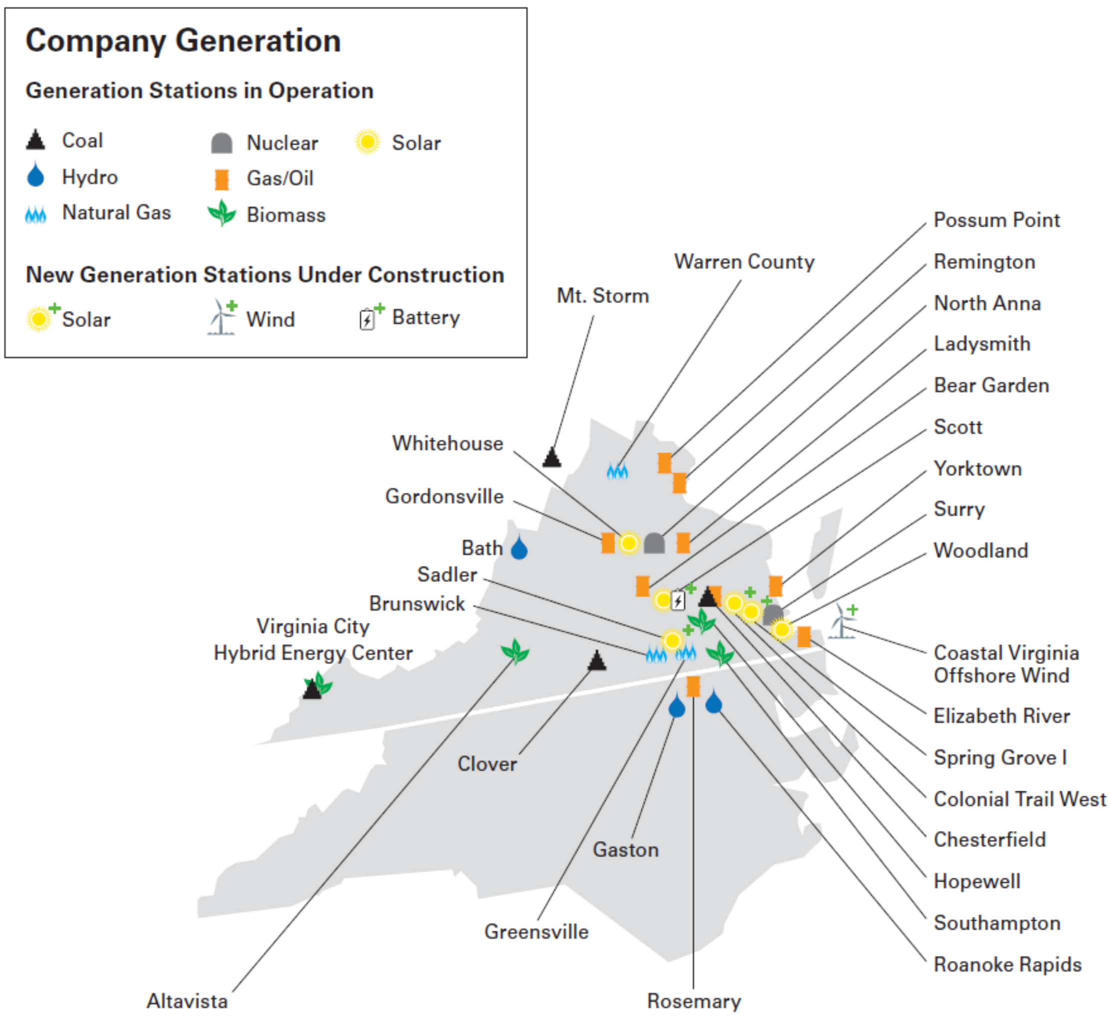


Appendices 5A through 5E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Appendix 5F provides a summary of the existing capacity by fuel class. Appendices 5G and 5H provide energy generation by type and by the system output mix. Appendix 5I provides a list of all Company-build or third-party PPA solar and wind generating facilities placed in service, under construction, or under development since July 1, 2018. Appendix 5O provides a list of renewable resources, and Appendix 5P provides a list of potential supply-side resources. Appendices 5Q and 5R present the Company's summer capacity position and seasonal capability, respectively. Appendix 5S provides the construction cost forecast for Alternative Plan B.

5.1.2 Company-Owned System Generation

The Company's existing system generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 5.1.2.1. This diverse fleet of 90 generation units includes 4 nuclear, 8 coal, 9 CCs, 40 CTs, 3 biomass, 2 heavy oil, 6 pumped storage, 14 hydro, and 4 solar with a total summer capacity of approximately 20,063 MW.

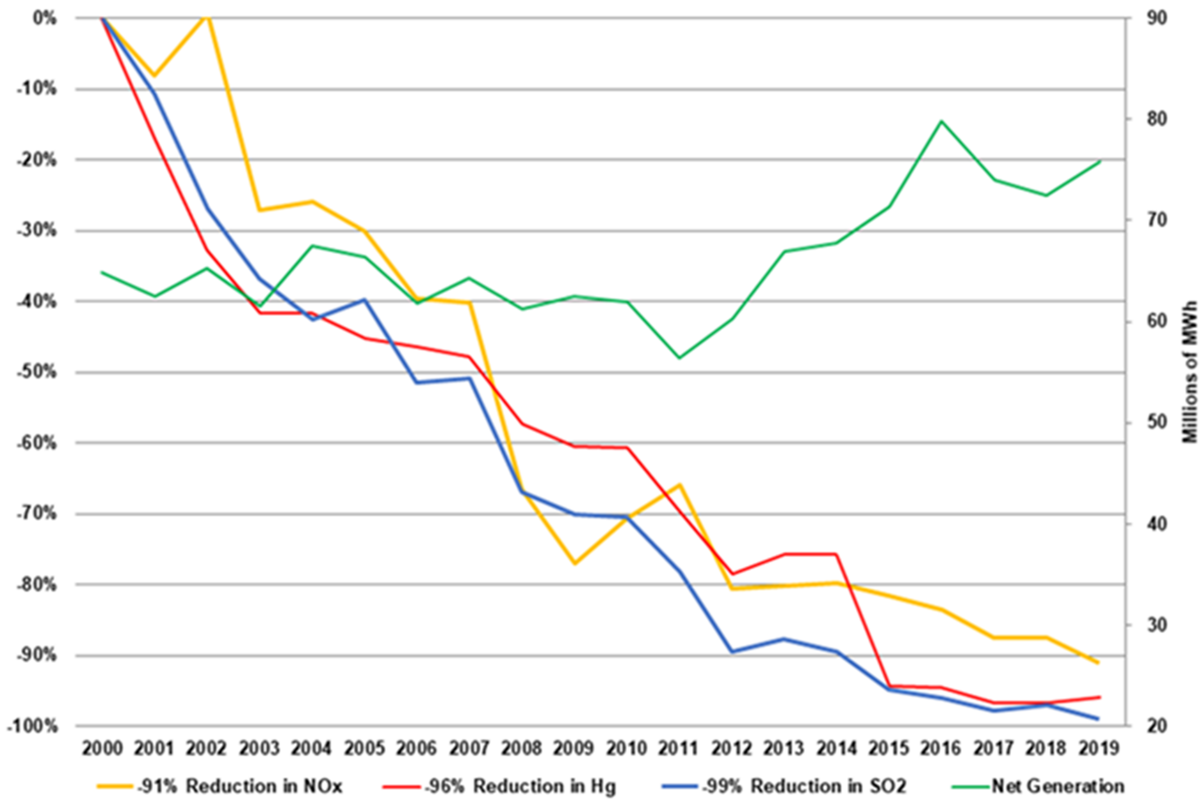
Figure 5.1.2.1 – Company Generation Resources



The Company currently owns and operates 667 MW of renewable resources, including solar, hydro, and biomass, with an additional 210 MW (nameplate) under construction. The Company also owns and operates four nuclear facilities (3,348 MW), providing significant zero-carbon generation for its customers.

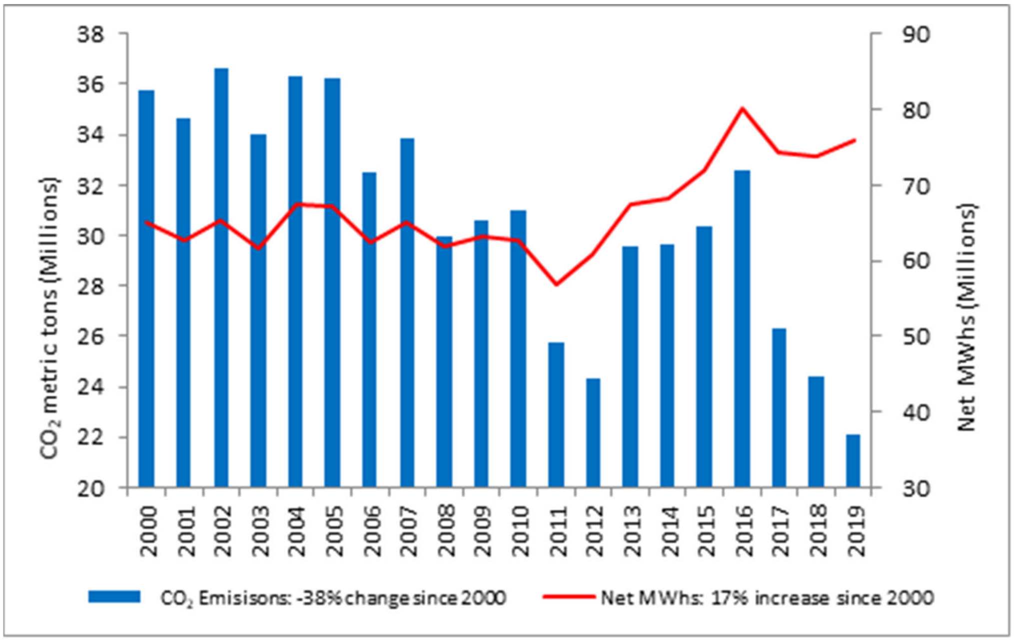
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, the conversion to dry ash handling, and the addition of air pollution controls. This strategy has resulted in significant reductions of air pollutants such as NO_X, SO_2, and mercury, as shown in Figure 5.1.2.2, and has also reduced the amount of coal ash generated and the amount of water used.

Figure 5.1.2.2 – Company Annual Reduction in Emissions by Percent



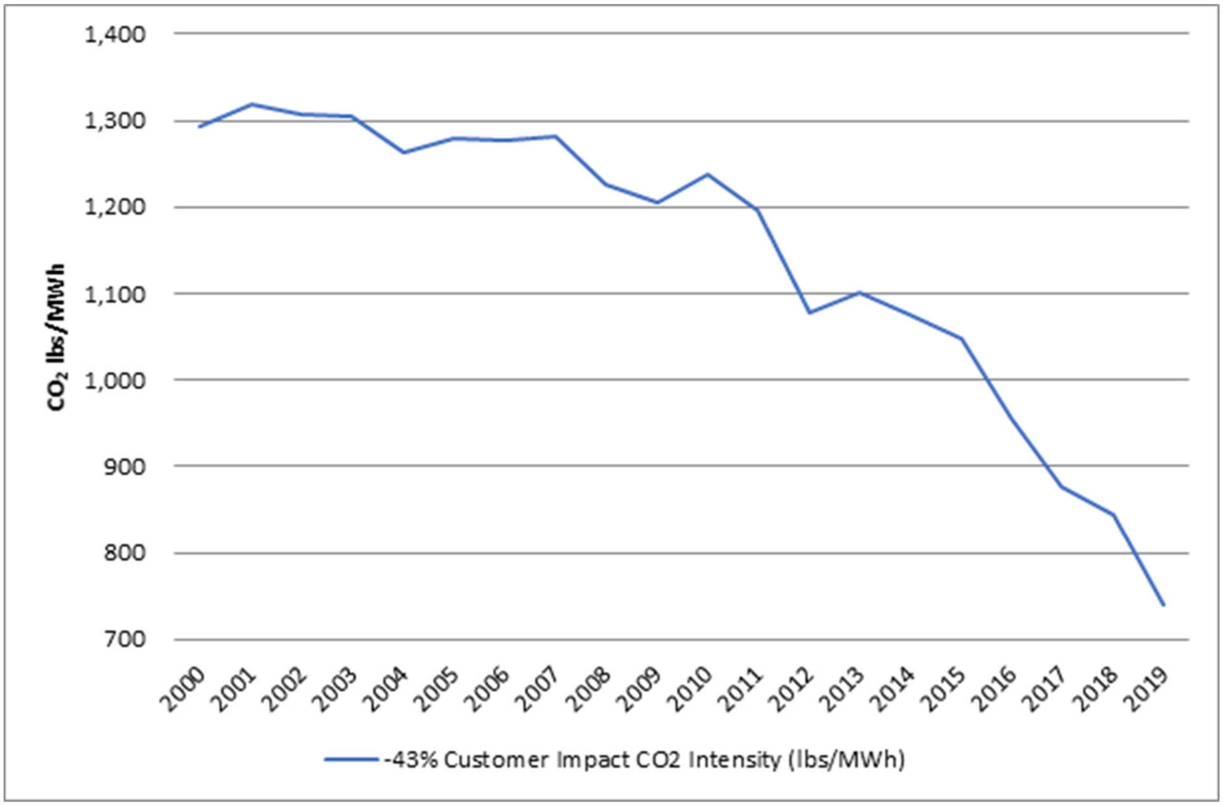
The Company develops a comprehensive GHG inventory annually. The Company's direct CO_2 equivalent emissions (based on ownership percentage) were 22.1 million metric tons in 2019 compared to 24.6 million metric tons in 2018. The Company has been a leader in reducing CO_2 emissions through retiring certain units; building additional efficient and lower-emitting natural gas-fired power generating sources and carbon-free renewable energy sources, such as solar; and maintaining its existing fleet of non-emitting nuclear generation. As shown in Figure 5.1.2.3, from 2000 through 2019, the Company has reduced the CO_2 emissions in tons from its power generation fleet serving Virginia jurisdictional customers by 38%, while power production has increased by 17%.

Figure 5.1.2.3 – Company CO_2 Mass Reductions versus Net Generation



The Company's integrated business strategy has also resulted in significant reduction in CO_2 emission intensity. CO_2 intensity is the amount of emissions per MWh delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, NUGs, and net purchased power. As shown in Figure 5.1.2.4, customer impact CO_2 intensity has decreased by 43% since 2000.

Figure 5.1.2.4 – Customer Impact CO_2 Intensity



5.1.3 Non-Utility Generation

A portion of the Company's load and energy requirement is supplemented with contracted NUGs. The Company has existing contracts with fossil-burning and renewable behind-the-meter NUGs for capacity of approximately 812 MW (nameplate).

For modeling purposes, the Company assumed that its NUG capacity would be available as a firm generating capacity 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 generating 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.

5.2 Evaluation of Existing Generation

The Company continuously evaluates various options with respect to its existing fleet, cognizant of environmental regulations and other policy considerations.

5.2.1 Retirements

As discussed in Section 1.2, the VCEA mandates the retirement of carbon-emitting generation on a specific schedule unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric services:

- Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024;
- Altavista, Hopewell, and Southampton (biomass) by 2028; and
- All remaining generation units that emit CO_2 as a byproduct of combustion by 2045.

Separate from these mandates, and consistent with prior Plans, the Company completed a unit evaluation economic analysis focused on coal-fired, heavy-oil fired, and large combined cycle Company generation facilities under market conditions.

Global assumptions included potential carbon regulations as well as market forecasts consistent with four ICF commodity forecast scenarios: No CO_2 Tax, Mid-Case Federal CO_2 with Virginia in RGGI, Virginia in RGGI and High-Case Federal CO_2.

A combination of PLEXOS production-cost modeling software and Excel models were used to calculate a unit NPV to customers over the next ten years. Unit NPVs were derived by comparing the total unit costs, including O&M and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues. Negative NPV results indicated an economic benefit of unit retirement to customers compared to continued operations of the unit in the PJM market.

The results of the analysis are included in Figure 5.2.1.1. In general, it can be concluded that the Company's coal-fired power plants located in Virginia continue to face pressure due to unfavorable market conditions and carbon regulations. Coal-fired generating facilities Chesterfield Units 5 and 6 and Clover Units 1 and 2 had negative NPVs under all four scenarios, including No CO_2 Tax. Mount Storm's coal-fired Units 1 through 3 showed positive NPVs in all four cases with a higher upside potential under Virginia in RGGI and the No CO_2 Tax scenarios. Heavy oil-fired power station Yorktown Unit 3 had negative NPVs in all four scenarios.

Figure 5.2.1.1 – Retirement Analysis Results

Units	No CO_2 Tax	Virginia in RGGI	Mid-Case Federal CO_2 with Virginia in RGGI	High-Case Federal CO_2
Chesterfield 5 - 6	-	-	-	-
Clover 1 - 2	-	-	-	-
Mt. Storm 1 - 3	+	+	+	+
Yorktown 3	-	-	-	-

Based on the above results and other factors, including but not limited to power prices and the retirement-related mandates in the VCEA, the Company anticipates retiring Yorktown Unit 3 and Chesterfield Units 5 and 6 in 2023. Other than these units, inclusion of a unit retirement in this 2020 Plan should be considered as tentative only. The Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units for potential retirement.

5.2.2 Uprates and Derates

Efficiency, generation output, and environmental characteristics of units are reviewed as part of the Company's normal course of business. Many of the uprates and derates occur during routine maintenance cycles or are associated with standard refurbishment. However, several unit ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations. Appendix 5K provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

5.2.3 Environmental Regulations

There are a number of final, proposed, and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife. For further discussion on significant developments to environmental regulation, see Sections 1.3 and 1.11.

5.3 Generation Under Construction

The Company currently has four generation projects under construction for which the SCC has issued a certificate of public convenience and necessity: (i) the CVOW demonstration project; (ii) Spring Grove 1 Solar Project; (iii) Sadler Solar Project; and (iv) the Battery Energy Storage System at Scott Solar Facility. Appendix 3A provides details on each project.

5.4 Generation Under Development

The Company currently has solar, offshore wind, pumped storage, and CT generation projects under development. The Company is also pursuing subsequent license extensions for its nuclear facilities. The following sections provide details on these projects, as does Appendix 3B.

The Company has paused material development activities for North Anna 3 following receipt of the combined operating license ("COL") in 2017. The Company is currently incurring minimal capital costs associated with North Anna 3 specific to the administrative functions of maintaining the COL.

5.4.1 Solar

The Company issued a request for proposal ("RFP") for new solar and wind resources in August 2019. The Company is currently evaluating the results of that RFP and intends to bring new Company-build and PPA resources before the SCC for approval as part of its annual plan regarding the development of solar, onshore wind, and energy storage required by the VCEA.

5.4.2 Offshore Wind

The Company is actively participating in offshore wind policy and innovative technology development to identify ways to advance offshore wind generation responsibly and cost-effectively.

The CVOW demonstration project—the Mid-Atlantic's first offshore wind project in a federal lease area—is under construction with a targeted in-service date by the end of 2020. This demonstration project is an important first step toward offshore wind development for Virginia and the United States. Along with clean energy, it is providing the Company valuable experience in permitting, constructing, and operating offshore wind resources, which will help inform utility-scale development of the adjacent 112,800 acre wind lease area.

As discussed in Section 1.2, the VCEA specifies that the construction or purchase of up to 5,200 MW of offshore wind capacity is in the public interest. In September 2019, the Company filed with PJM to interconnect more than 2,600 MW of offshore wind capacity by 2026 ("CVOW commercial project"), enough to power more than 650,000 homes during peak winds.

On January 7, 2020, the Company selected Siemens Gamesa Renewable Energy as the preferred turbine supplier for the CVOW commercial project with the intent to provide their latest state-of-the-art wind turbine, based on its proven Offshore Direct Drive platform. Ongoing efforts of this project include ocean survey work that will be performed in 2020 to support the development of the Construction and Operations Plan, which is expected to be submitted to the Bureau of Ocean Energy Management in late 2020. Pending regulatory approval, the CVOW commercial project is expected to be in-service by the end of 2026.

5.4.3 Pumped Storage

Pumped storage hydroelectric power is a mature proven storage technology. It can also serve as a system-stabilizing asset to accommodate the intermittent and variable output of renewable energy sources such as solar and wind. Virginia Senate Bill No. 1418 became law effective on July 1, 2017, and supported construction of "one or more pumped hydroelectric generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source . . . located in the coalfield region of the Commonwealth." On September 6, 2017, the Company filed a preliminary permit application with FERC for a location in Tazewell County, Virginia. This application was approved on December 11, 2017, and the Company is continuing to conduct feasibility studies for a potential pumped storage facility at the Tazewell County site.

5.4.4 Extension of Nuclear Licensing

An application for a subsequent license renewal is allowed during a nuclear plant's first period of extended operation—that is, in the 40 to 60 years range of its service life. Surry Units 1 and 2 entered into that initial license renewal period in 2012 and 2013, respectively. North Anna Units 1 and 2 entered or will enter into that period in 2018 and 2020, respectively. The Company has continued to track the preliminary cost estimates for the extension of the nuclear licenses at its Surry and North Anna Units.

In November 2015, the Company notified the NRC of its intent to file for subsequent license renewal for its two nuclear units (1,676 MW total) at Surry in order to operate an additional 20 years, increasing their operating life from 60 to 80 years. As with other nuclear units, Surry was originally licensed to operate for 40 years and then renewed for an additional 20 years. Absent subsequent license renewal approval, the existing licenses for Surry Units 1 and 2 will expire in 2032 and 2033, respectively. In support of the application development, the NRC finalized guidance documents in early July 2017, related to developing and reviewing subsequent license renewal applications. The Surry subsequent license renewal application was submitted to the NRC on October 15, 2018, in accordance with Title 10 of the Code of Federal Regulations ("CFR") Part 54.

The Surry subsequent license renewal application was subsequently declared "technically sufficient and available for docketing" by the NRC on December 10, 2018, which began the safety and environmental reviews required for the renewed licenses. Several NRC audits and public meetings have been conducted during both the safety and environmental reviews in late 2018 and 2019 related to this licensing action. The NRC staff has asked requests for additional information ("RAIs") during this review period seeking clarification or additional action to be taken by the Company prior to entering the subsequent period of operation. These environmental and safety RAIs have been addressed to the satisfaction of the NRC staff.

As a result, the NRC issued the Final Safety Evaluation Report ("SER") for Surry Power Station on March 9, 2020. On the basis of its review of the Surry subsequent license renewal application, the NRC staff determined that the requirements of 10 CFR 54.29(a) have been met for the subsequent license renewal of Surry Units 1 and 2. The NRC also issued the Final Supplemental Environmental Impact Statement ("FSEIS") on April 6, 2020. The NRC staff's conclusion was "that the adverse environmental impacts of license renewal for Surry are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable."

The Advisory Committee on Reactor Safeguards ("ACRS") Full-Committee meeting was conducted on April 8, 2020, with unanimous approval by the committee to approve the renewal of the operating licenses for Surry Units 1 and 2.

The NRC Director of Nuclear Reactor Regulation will make a decision for renewed licenses for Surry Units 1 and 2 based on the issuance of the FSEIS, Final SER and the ACRS letter of recommendation in June 2020. This will preserve the option to continue operation of Surry Units 1 and 2 until 2052 and 2053, respectively.

The Company notified the NRC in November 2017 of its plans to file an subsequent license renewal application for its two nuclear units (1,672 MW total) at North Anna in accordance with 10 CFR Part 54 in late 2020. Absent subsequent license renewal approval, the existing licenses for the two units will expire in 2038 and 2040, respectively. The review process for North Anna will remain unchanged, so the expected outcome would be similar to Surry. The renewed licenses for North Anna would be expected 18 months following the NRC declaring the subsequent license renewal application as technically sufficient and available for docketing, which is expected within 45 to 60 days following the Company's submittal. Currently, the forecast receipt of the renewed licenses for North Anna Units 1 and 2 is June 2022, based on a targeted submittal date in October 2020.

5.4.5 Combustion Turbines

In order to preserve the option to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities in the near term, the Company is evaluating sites and equipment for the construction of gas-fired CT units.

5.5 Future Supply-Side Generation 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 the 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 PJM. The technology's ability to be dispatched is based on whether the resource is able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand and supply conditions. Further, analysis of the alternative resources 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 and O&M. Figure 5.5.1 summarizes the resource types that the Company reviewed as part of the generation planning process. Those resources considered for further analysis in the busbar (*i.e.*, LCOE) screening model are identified in the final column.

Further analysis was conducted in PLEXOS 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 PLEXOS simulation analysis further refines the Company's analysis and assists in selecting the type and timing of additional resources that economically fit the customers' current and future needs.

Figure 5.5.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource	PLEXOS Resource
Combined Cycle - 3X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 2X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 1X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Aero-derivative Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Large Nuclear	Baseload	Yes	Uranium	Yes	No
Nuclear Small Modular Reactor	Baseload	Yes	Uranium	Yes	Yes
Biomass	Baseload	Yes	Renewable	Yes	No
Fuel Cell	Baseload	Yes	Natural Gas	Yes	No
Supercritical Pulverized Coal with CCS	Intermediate	Yes	Coal	Yes	No
Solar & Aero-derivative CT	Peak	Yes	Renewable	Yes	No
Solar	Intermittent	No	Renewable	Yes	Yes
Wind - Onshore	Intermittent	No	Renewable	Yes	Yes
Wind - Offshore	Intermittent	No	Renewable	Yes	Yes
Battery Generic (30 MW)	Peak	Yes	Varies	Yes	Yes
Pumped Storage (300 MW)	Peak	Yes	Renewable	Yes	Yes
Combined Heat and Power	Peak	Yes	Varies	Yes	Yes

5.5.1 Supply-Side Resource Options

The following sections provide details on certain newer supply-side resource options the Company has considered. Previous Plans provide additional details on the more proven technologies, including biomass, CCs, CTs, nuclear, and solar. In addition, Section 5.4 provides additional details on generation currently under development, including offshore wind and pumped storage.

Aero-derivative Combustion Turbine

Aero-derivative CT technology consists of a gas generator that has been derived from an existing aircraft engine and used in an industrial application. Designed for a small footprint and low weight using modular construction, aero-derivative CTs utilize advanced materials for high efficiency and fast start-up times with little or no cyclic life penalty. Aero-derivative CTs have been designed for quick removal and replacement, allowing for fast maintenance and greatly reduced downtimes, and resulting in high unit availability and flexibility. This is a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatchable renewable resources, such as solar and wind.

Combined Heat and Power / Waste Heat to Power

Combined heat and power ("CHP") is the use of a power station to generate electricity and useful thermal energy from a single fuel source. CHP plants capture the heat that would otherwise be wasted to provide useful thermal energy, usually in the form of steam or hot water. The recovery of otherwise wasted thermal energy in the CHP process allows for more efficient fuel usage.

CHP's reduction in primary energy use through fuel efficiency leads to lower greenhouse gas emissions.

Waste heat to power ("WHP") is a type of combined heat and power that generates electricity through the recovery of qualified waste heat resources. WHP captures heat byproduct discarded by existing industrial processes and uses that heat to generate power. Industrial processes that involve transforming raw materials into useful products all release hot exhaust gases and waste streams that can be captured to generate electricity. WHP is another form of clean energy production.

The Company will continue to track this technology and its associated economics based on site and fuel resource availability.

Energy Storage

There are five main types of energy storage technologies: electromechanical, electrochemical, thermal, chemical, and electrical.

Electromechanical storage involves creating potential energy, which can be converted to kinetic energy. Pumped storage hydro, the most commonly used electromechanical storage technology, requires pumping large quantities of water to a reservoir at a higher elevation than the source, which creates potential energy that can be converted to kinetic energy that then spins a water turbine. Pumped storage hydro is a mature technology compared to other types of energy storage, and it represents the largest amount of installed storage capacity in the United States. See Section 5.4.3 for a discussion of the pumped storage hydroelectric facility under development. Other examples of electromechanical storage include flywheels and compressed air energy storage.

Electrochemical (or battery) storage involves storing electricity in chemical form. One advantage of electrochemical storage is the fact that electrical and chemical energy share the same carrier—the electron—which limits efficiency losses due to converting one form of energy to another. Lithium ion is now the most commonly used type of battery in utility-scale projects because lithium ion costs have been falling rapidly for nearly a decade. This decrease in cost is attributable to advancements in battery design, efficiency gains in manufacturing, and increased supply. Other examples of electrochemical storage include lead acid batteries, sodium sulfur batteries, and flow batteries.

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 a power station black start, 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. 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 approximates dispatchability for 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 SCC recently approved the Company's application to pilot three lithium ion battery energy storage systems for different use cases. The results of these pilots will inform future deployment of batteries.

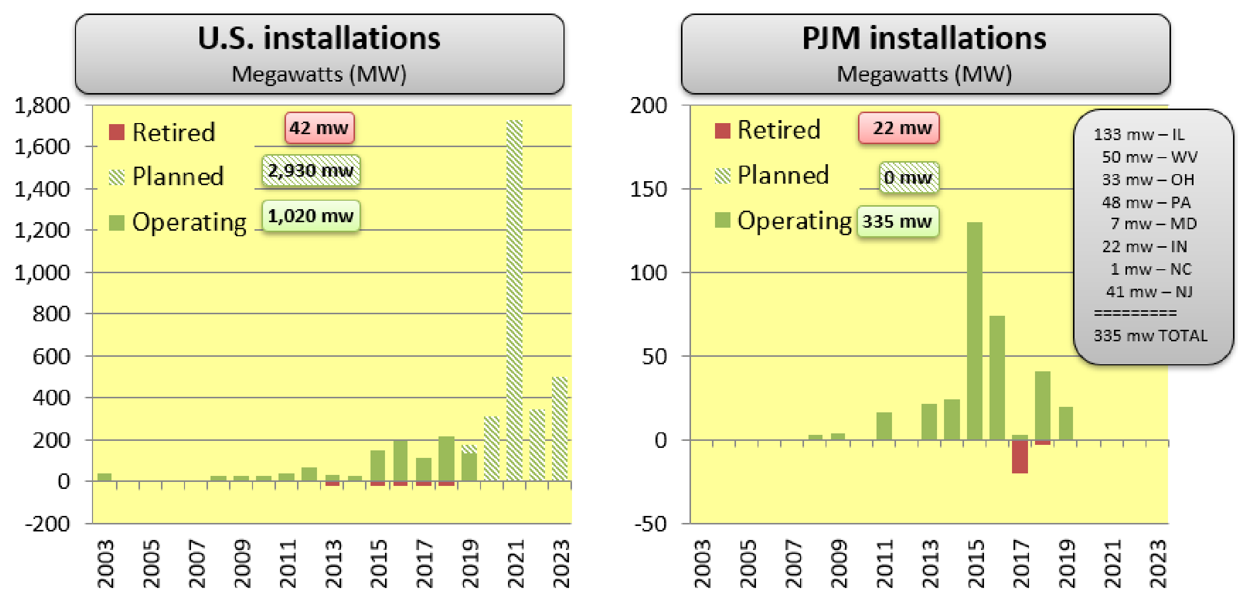
Thermal storage involves converting stored heat into energy, or supplying cool air to reduce air conditioning load. Water heaters, ice storage, and chilled water storage are all examples of thermal storage.

Chemical storage involves altering the molecular structure of compounds (such as water) by splitting or combining molecules. For example, hydrogen gas can be created by splitting H_2O molecules into H_2 and O_2. The H_2 (hydrogen gas) can be stored and later burned to produce steam to power a turbine. Another example of chemical storage is power-to-gas conversion, which converts electrical power into gaseous fuel.

Electrical storage primarily refers to super capacitors and magnetic energy storage, which can provide short, powerful bursts of energy to jumpstart other technologies.

Cost considerations and technology maturity have restricted widespread deployment of most of these technologies, with the exception of pumped storage hydroelectric power and batteries. At present, lithium-ion batteries and pumped storage are the most commercially viable energy storage technologies for utility-scale projects. Based on the most current information sourced from the U.S. Energy Information Administration, the amount of utility-scale battery storage installed in the entire United States is just over 1,000 MW, as shown in Figure 5.5.1.1. Of those 1,000 MW, only 335 MW are located within the PJM region.

Figure 5.5.1.1 – Utility-Scale Battery Storage Installations



As discussed in Section 1.2, the VCEA requires the Company to build 2,700 MW of energy storage by 2035. The Company will continue to study energy storage to determine the feasibility of constructing this quantity of energy storage capacity.

Fuel Cell

Fuel cells convert chemical energy from hydrogen-rich fuels into electricity and heat, there is no burning of the fuel. Fuel cells emit water and CO_2, resulting in power production that is almost entirely absent of NO_x, SO_x, or particulate matter. Similar to a battery, a fuel cell is comprised of many individual cells that are grouped together to form a fuel cell stack. Each individual cell contains an anode, a cathode, and an electrolyte layer. When a hydrogen-rich fuel, such as clean natural gas or renewable biogas, enters the fuel cell stack, it reacts electrochemically with oxygen (*i.e.*, ambient air) to produce electric current, heat, and water. While a typical battery has a fixed supply of energy, fuel cells continuously generate electricity as long as fuel is supplied. Fuel cells were invented in 1932 and put to commercial use by NASA in the 1950s. They are now most common as a power source for buildings and remote areas, but continual improvements in technology are quickly bringing them into wider use.

Integrated-Gasification Combined Cycle with Carbon Capture Sequestration

Integrated-gasification CC plants use a gasification system to produce synthetic natural gas from coal that is then used to fuel a CC. The gasification process produces a pressurized stream of CO_2 before combustion, which, as research suggests, provides some advantages in preparing the CO_2 for CCS systems. Integrated-gasification CC systems remove a greater proportion of other air effluents in comparison to traditional coal units.

Reciprocating Internal Combustion Engine

Reciprocating internal combustion engines use reciprocating motion to convert heat energy into mechanical work. Stationary reciprocating engines differ from mobile reciprocating engines in that they are not used in road vehicles or non-road equipment.

There are two basic types of stationary reciprocating engines, spark ignition and compression ignition. Spark ignition engines use a spark (across a spark plug) to ignite a compressed fuel-air mixture. Typical fuels for such engines are gasoline and natural gas. Compression ignition engines compress air to a high pressure, heating the air to the ignition temperature of the fuel, which then is injected. The high compression ratio used for compression ignition engines results in a higher efficiency than is possible with spark ignition engines. Diesel fuel oil is normally used in compression ignition engines, although some are duel-fueled (*i.e.*, natural gas is compressed with the combustion air and diesel oil is injected at the top of the compression stroke to initiate combustion).

Small Modular Reactors

Small modular reactors ("SMRs") are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured largely off-site in factories, and then delivered and installed on-site in modules. The smaller power output of SMRs when compared to conventional baseload nuclear units currently in operation offers a number of advantages, including reduced land surface area, potential for reduced security and emergency planning zone requirements, lower initial capital and operating costs, and flexibility in meeting specific power needs by staging multiple units in the same or multiple locations. A typical SMR design entails underground placement of reactors and spent-fuel storage pools and a natural cooling feature that can continue to function in the absence of external power. SMR design development and permitting have advanced with some designs currently under review by the NRC. The Company will continue to monitor the industry's ongoing research and development regarding this technology. The federal government recently approved partial co-funding for up to two demonstration projects. The Company is reviewing and evaluating the potential for participation in this funding opportunity in support of its emission reduction targets.

5.5.2 Levelized Busbar Costs / Levelized Cost of Energy

The Company's busbar model was designed to estimate the levelized cost of energy of various generating resources on an equivalent basis. The busbar results show the LCOE of various generating resource technologies 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 O&M costs, expected service life, and overnight construction costs.

Figures 5.5.2.1 and 5.5.2.2 display summary results of the busbar model comparing the economics of the different technologies. The results are separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources for the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

Figure 5.5.2.1 - Dispatchable LCOE (2023 COD)

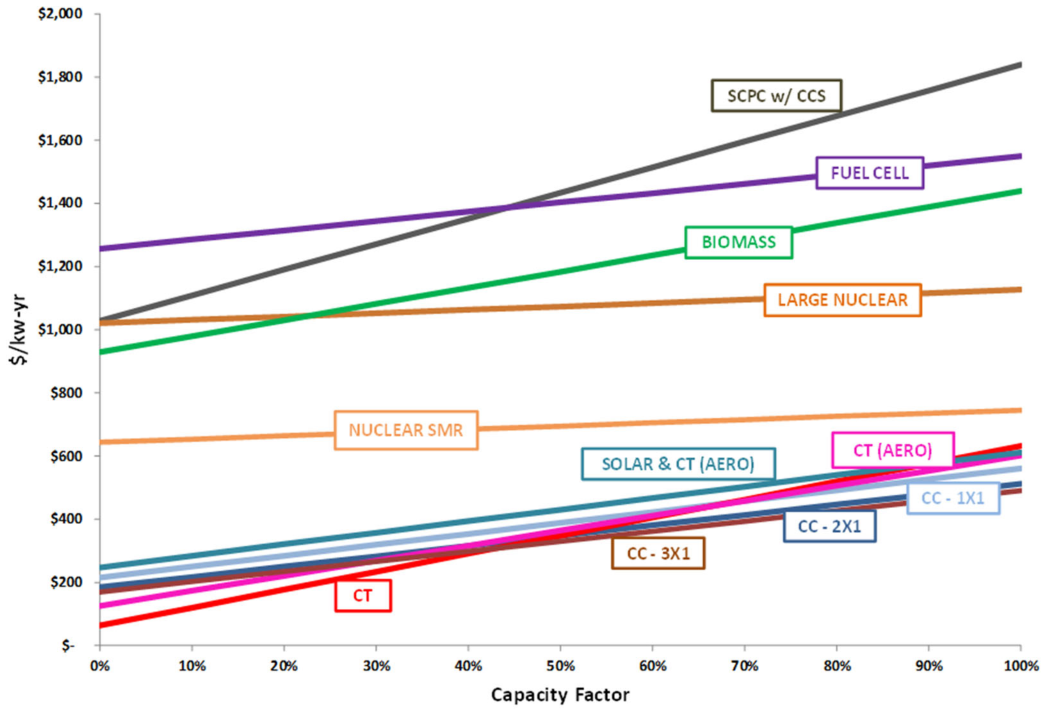
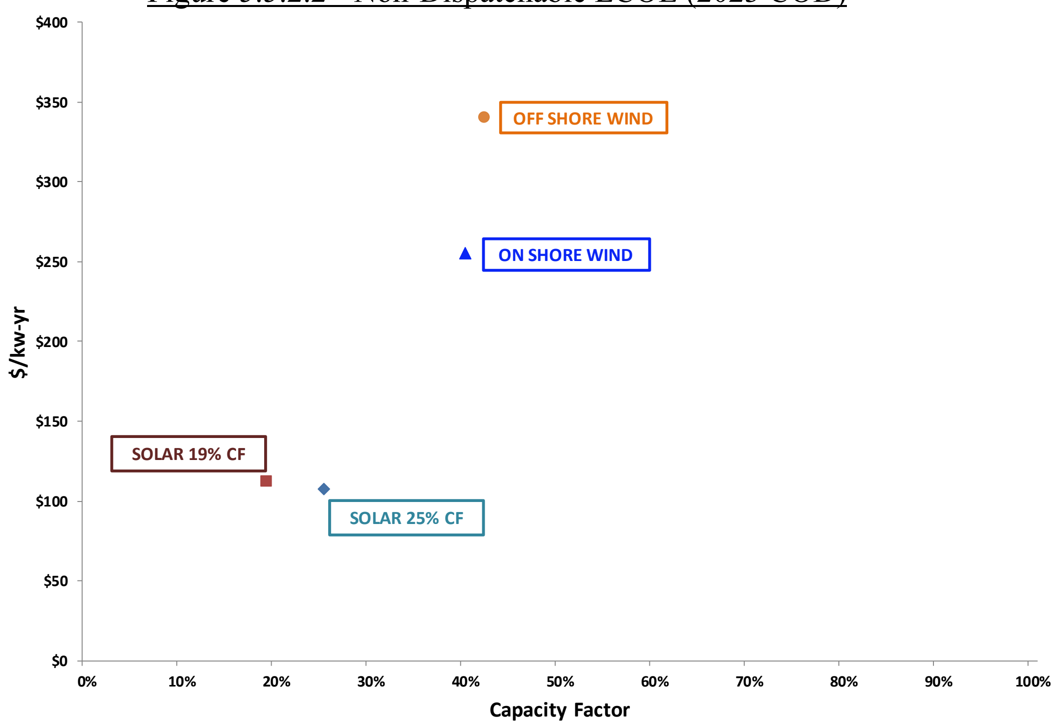


Figure 5.5.2.2 - Non-Dispatchable LCOE (2023 COD)



Appendix 5M contains the tabular results of the screening level analysis. Appendix 5N displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated construction costs.

In Figure 5.5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with LCOE above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher LCOE resources, however, may be necessary to achieve other constraints like those required by carbon regulations. Figures 5.5.2.1 and 5.5.2.2 allow comparative evaluation of resource types.

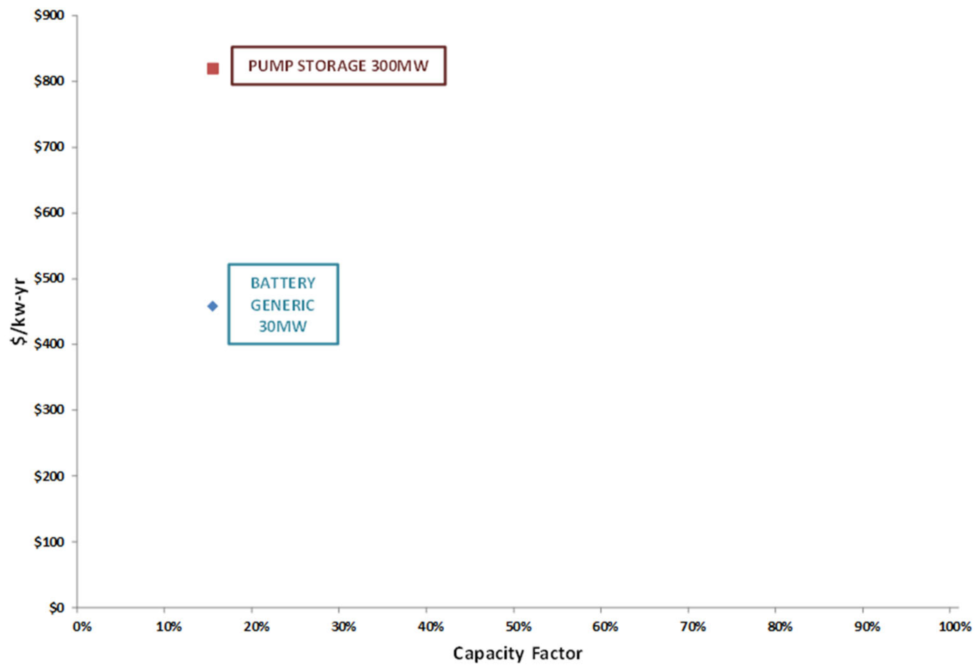
In Figure 5.5.2.1, the value of each cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of operating the unit, including fuel, emissions, and any REC or production tax credit ("PTC") value a given unit may receive.

Figure 5.5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods than dispatchable resources, requiring more capacity to maintain the same level of system reliability. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability.

As shown in Figure 5.5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 25% for meeting the Company's peaking requirements. The CC 3x1 technology is the most economical option for capacity factors greater than approximately 25%. As depicted in Figure 5.5.2.2, solar is a competitive choice at capacity factors of approximately 25%.

Figure 5.5.2.3 shows the estimated LCOE for a 300 MW pumped storage facility and generic 30 MW 4-hour battery. All LCOE are based on a 15% capacity factor, which was derived from the historical performance of the Company's pumped storage facilities, and projected performance of future energy storage technologies, as calculated by the PLEXOS model.

Figure 5.5.2.3 - Energy Storage LCOE (2023 COD)



The assessment of alternative resource types and the busbar screening process provides a simplified 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.

5.5.3 Third-Party Market Alternatives

During the last several years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territories.

In Virginia, the Company has issued an annual RFP for utility-scale solar and wind generating facilities since 2015. These RFPs have resulted in both Company-owned solar facilities and solar PPAs. Outside of the utility-scale solar and wind RFPs, the Company entered into PPA agreements for several solar facilities totaling 67 MW. The Company has also issued RFPs for small-scale solar resources. The Company will continue to issue annual RFPs for solar and wind resources, consistent with the competitive procurement requirements of the VCEA.

In North Carolina, the Company has signed 91 PPAs totaling approximately 686 MW (nameplate) of new solar NUGs. Of these, 572 MW (nameplate) are from 80 solar projects that were in operation as of March 2020. The majority of these projects are qualifying facilities contracting to sell capacity and energy at the Company's published North Carolina Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act.

5.6 Challenges Related to Significant Volumes of Solar Generation

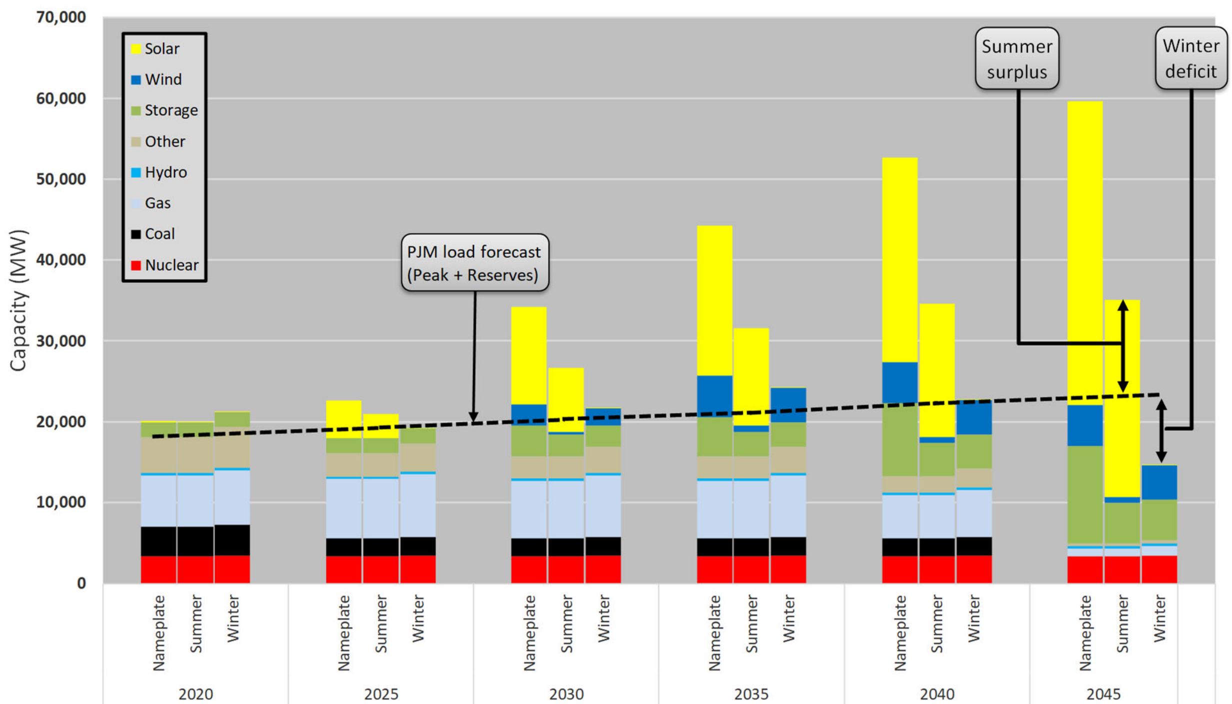
All Alternative Plans in this 2020 Plan include significant development of solar resources, as shown in Section 2.2. Based on current technology, challenges will arise as increasing amounts of these non-dispatchable, intermittent resources are added to the system. This section seeks to identify these challenges, which include intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load, as well challenges related to system restoration. This section also discusses challenges related to constructing the level of solar generation in Alternative Plans B through D. In this 2020 Plan, Alternative Plan B best addresses these challenges based on current technology. But the Company stands ready to meet these challenges with continued study, technological advancement, and innovation, and will provide the results of these advancements in future Plans and update filings.

5.6.1 Challenges Related to Capacity

Solar generation significantly contributes to meeting peak demand in the summer, but barely contributes to meeting winter peak demand. This is because summer peak demand occurs during late afternoon hours when the sun is typically shining and, consequently, when the solar facilities are producing energy. In contrast, winter peak demand typically occurs in the early morning hours when the sun is beginning to rise, and when solar facilities are just starting to ramp up production.

As the Company adds increasing amounts of solar resources to the system, this will result in the system having excess capacity in the summer, but not having enough capacity in the winter. For example, Figure 5.6.1.1 shows the nameplate capacity, summer capacity, and winter capacity of existing and new resources in Alternative Plan D compared to the 2020 PJM Load Forecast. As can be seen, the Company has approximately 11,500 MW more capacity than needed in the summer in Alternative Plan D, but then has a deficit of approximately 8,800 MW in the winter.

Figure 5.6.1.1 – Alternative Plan D Capacity in Summer and Winter



Notes: "Other" = biomass, small combustion turbines, NUGs, demand response, purchases, & heavy oil units

Adding energy storage resources is one way the Company could meet this winter capacity deficit. The capacity value of energy storage resources is limited, however, by the size of the resource and by the time it takes to recharge. Significantly more energy storage capacity would be needed, both in magnitude and duration, as the peak gets steeper and as the period that those resources are expected to support the system becomes longer. The combination of these factors would likely lead to an overbuilt system (*i.e.*, a system with higher resource nameplate capacity compared to peak load). In addition, many forms of utility-scale energy storage are still in the early stages of development, as discussed further in Section 5.5.1, with higher costs relative to other current technologies. Technological advancements may provide other options to meet this challenge in the long term without necessitating an overbuild of the system.

The Company could also meet this challenge related to winter capacity in the future by buying capacity to fill the deficit to the extent required by PJM market rules. In this 2020 Plan, the Company assumed it would meet any winter deficit with capacity from the market. Historically, the Company was able to self-supply to meet the vast majority of all its capacity needs; Alternative Plans C and D rely heavily on the market to maintain the reliability of the system.

5.6.2 Challenges Related to Energy

In addition to challenges related to winter capacity, development of significant volumes of solar generation also present challenges related to energy. Specifically, the Company would likely need to import a significant amount of energy during the winter, but would need to export significant amounts of energy during the spring and fall. Figure 5.6.2.1 shows the level of imports for each Alternative Plan. Figure 5.6.2.2 shows what percentage of time in the year 2045 the Company must use imports to meet load. In addition, Figure 5.6.2.2 shows the percentage of time in year 2045 that imports are constrained by system limitations—5,200 MW for Plans A and B, and 10,400 MW for Plans C and D.

Figure 5.6.2.1 – Annual Imports for Each Alternative Plan

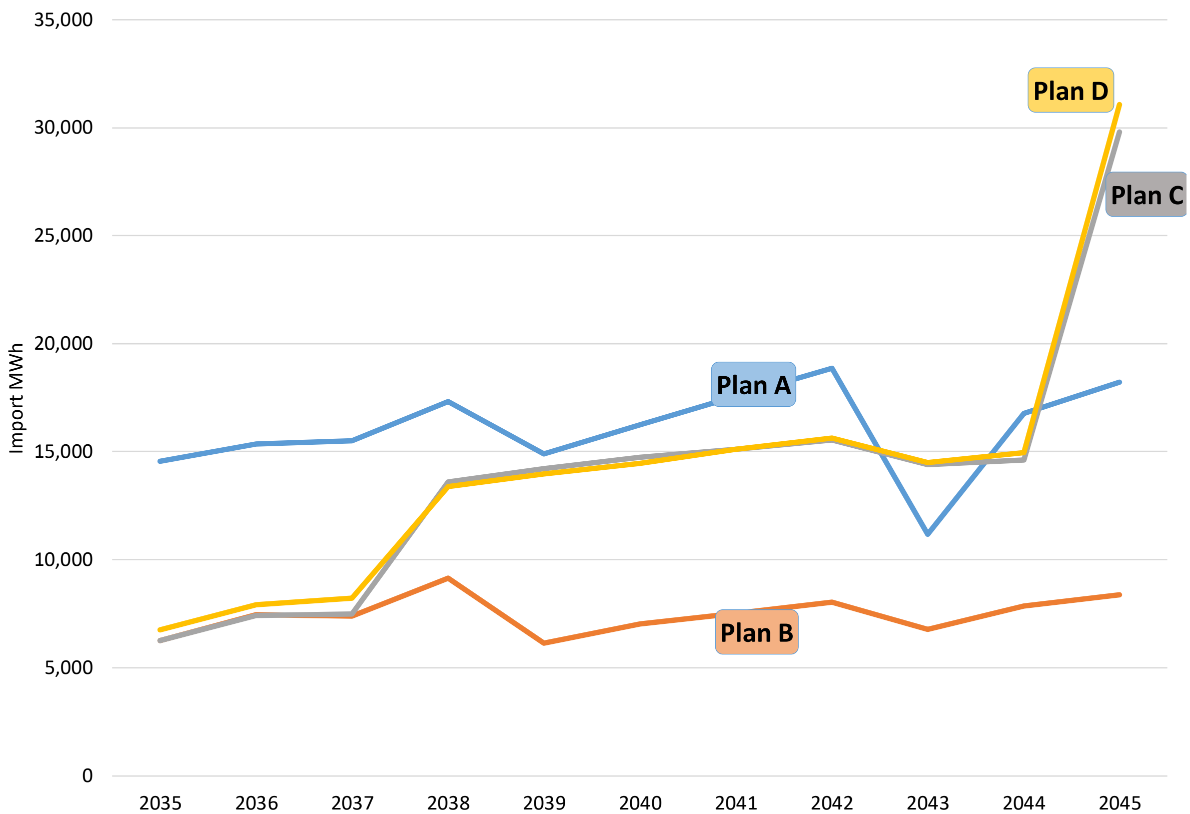
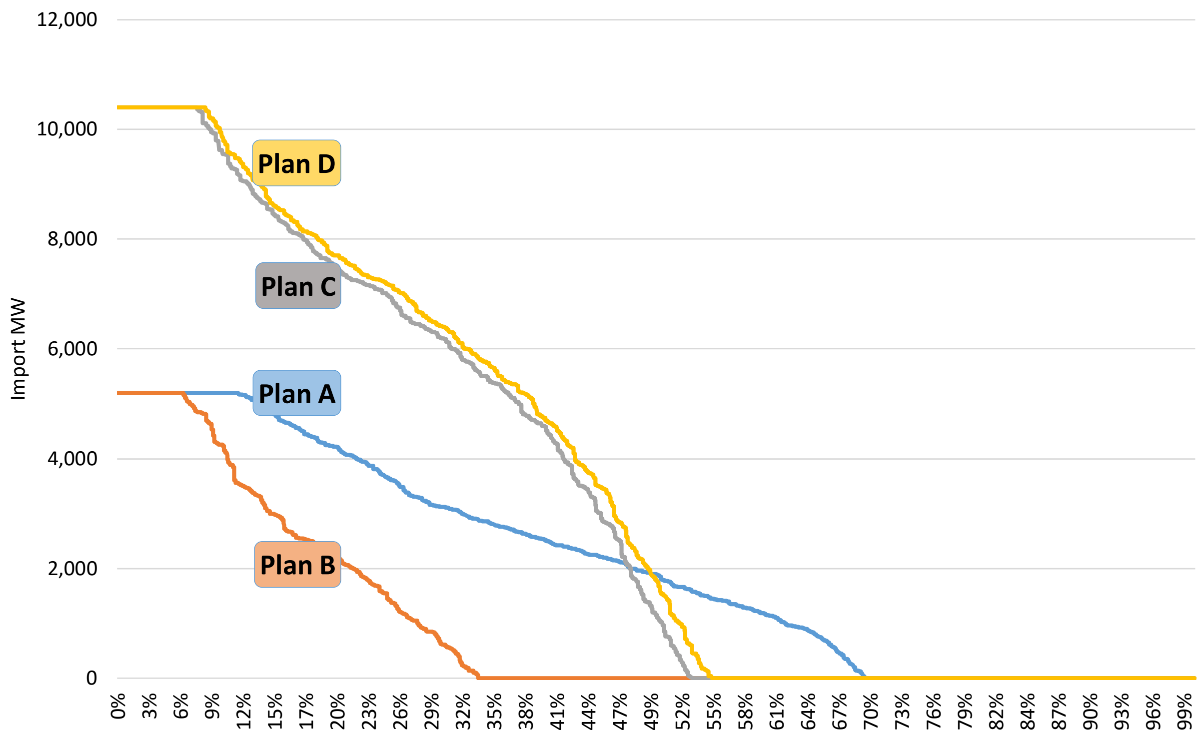


Figure 5.6.2.2 – Year 2045 Import Duration Curve



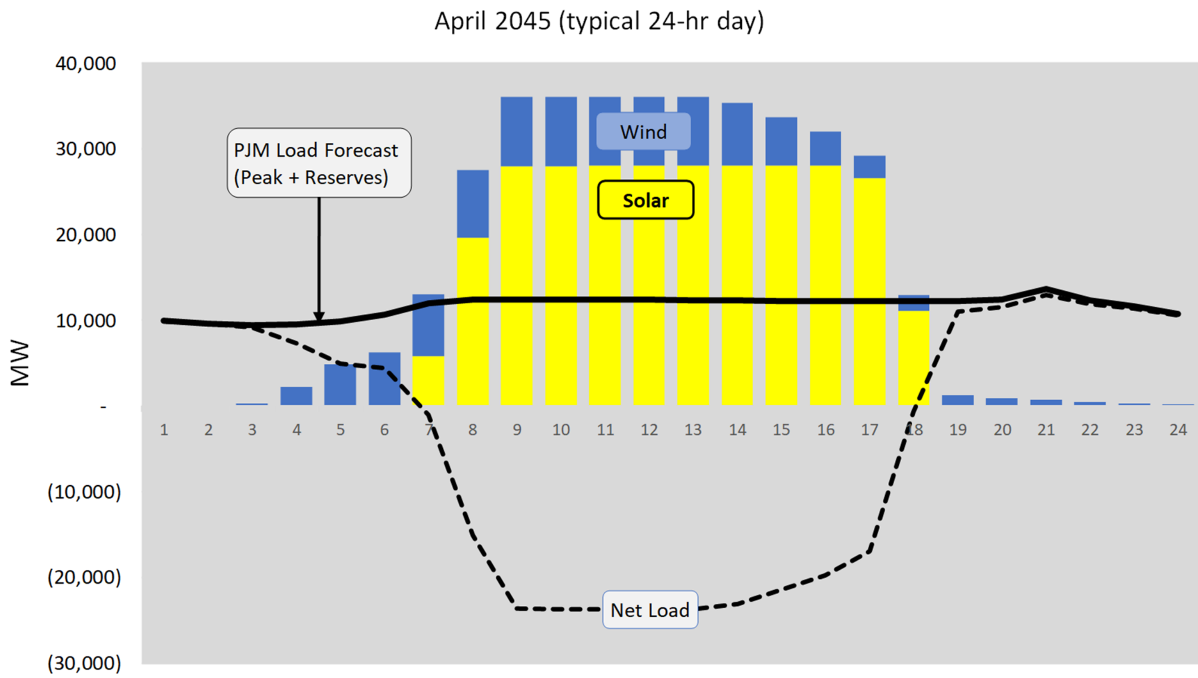
Importing significant energy presents its own challenges. Section 7.5 includes a discussion of the upgrades that would be needed to the Company's transmission system to physically import these increased levels of energy, as well as an estimate of those costs. Notably, relying on increased imports could also contribute to regional CO_2 emission because the imported power from PJM would come in part from carbon-emitting generation in the PJM region. Figure 2.2.6 shows regional carbon emissions for each Alternative Plan.

5.6.3 Challenges Related to the Solar Production Profile

Output from solar facilities generally tracks the sun, ramping up in the morning as the sun rises, producing consistently throughout the day subject to cloud cover, and then ramping down as the sun sets. This production profile generally (although not perfectly) fits well with customer demand in the summertime because customer demand is higher during the afternoon hours when solar production is high. In the spring and fall, however, as increasing amounts of solar generation is added to the system, solar can produce more energy than is needed to meet customer demand during the daytime.

Figure 5.6.3.1 shows the capacity of the solar and wind resources in Alternative Plan D during a typical day in April compared to the PJM Load Forecast. As can be seen, the inclusion of large amounts of solar and wind generation significantly alters the shape of the net load profile (*i.e.*, forecasted load less the non-dispatchable solar and wind energy) causing a dip in the middle of the day. This profile is commonly referred to as a "duck curve" because it produces a profile that resembles the silhouette of a duck. As Figure 5.6.3.1 shows, the Company would need additional energy at dawn and dusk, but would have excess energy during the daytime.

Figure 5.6.3.1 – Solar and Wind Capacity Compared to Load Forecast



The Company could address this challenge with additional energy storage resources, though some energy would be lost when storage resources are used. The Company could also increase the amount of energy it exports subject to system need, though this would be limited by transmission export capacity. The Company may also be limited in its ability to export excess energy in the spring and fall to the extent neighboring states elect to develop significant volumes of solar resources similar to Virginia and also have excess energy.

In some instances, it would become more economic to "dump" this excess energy when compared to the costs of building additional energy storage resources, increasing transmission export capacity, or facing negative market energy prices. From an operational perspective, energy is "dumped" by lowering the output levels of certain solar facilities during periods of low demand. One possible clean energy solution to this challenge, however, would be to utilize long-term storage solutions for this dump energy. For example, the Company could utilize this excess energy to create carbon-free hydrogen fuel that could subsequently be used in natural gas-fired generators. When hydrogen fuel is used in gas-fired generators, the byproduct is water rather than CO_2. The Company will continue to study these types of innovative alternatives to address challenges caused by increasing levels of solar generation on the system. Based on the advancements and innovations in the industry in the next 25 years, Virginia may need to adjust its RPS to accommodate other potential technologies that would provide clean energy while maintaining system reliability.

Another potential issue caused by the solar production profile shown in Figure 5.6.3.1 is the steep generation changes in the dawn and dusk periods. In a three-hour period, the system would have to ramp over 30,000 MW of supply—an extremely large magnitude, especially over that short of a duration. Essentially, the Company would be ramping up and down its entire fleet of dispatchable resources twice a day. Backup generation resources along with energy storage resources may be required to manage these large transitions.

5.6.4 Challenges Related to Black Start and System Restoration

"Black start" refers to the critical process of restoring the system without relying on the external transmission network to recover from a total or partial shutdown. Development of significant volumes of solar generation also present challenges in a black start event. The system has traditionally been set up to rely on dispatchable, quick-start units for black start, such as combustion turbines. Initial power from these units are used to start larger dispatchable generators, allowing even larger units (*e.g.*, nuclear) and customers to reconnect to the grid in a very logical and coordinated process. This process is largely a manual process for grid operators as they must maintain a fine balance between energy supply and demand; black start units thus have strict operational requirements to be available around-the-clock and be able to produce steady and predictable output. Such requirements impose difficulties for non-dispatchable, intermittent solar resources to be included in the system restoration plan.

In this 2020 Plan, Alternative Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability and energy independence, including challenges related to black start. The Company will continue to study how to address these black start-related challenges as the Company transition to a cleaner future, as discussed further in Section 7.5.5.

5.6.5 Challenges Related to Constructability

Beyond the system challenges that arise from adding increasing amounts of intermittent generation to the system, solar developers—including the Company—will face increasing challenges in permitting and constructing the amount of solar generation envisioned by the VCEA, as modeled in Alternative Plans B through D.

Utility-scale solar generating facilities require a significant amount of land. Based on current technology, every one megawatt of solar capacity requires approximately 10 acres of land. The VCEA requires this new solar capacity to be located in Virginia. Acquiring this amount of land—and receiving the required permits for that land—could prove increasingly difficult as development continues.

This difficulty in acquiring land and permitting projects will be exacerbated if localities and members of the public continue to raise objections to siting solar facilities in their communities. For example, in October 2019, the Culpepper County Board of Supervisors adopted new provisions to its Utility Scale Solar Development Policy intended "to limit 'utility scale solar sprawl.'" These new provisions would limit total solar development in the county to 2,400 acres—1% of the total land mass in Culpeper—and would limit the size of individual projects to 300 acres (the equivalent of approximately 30 MW). As another example, in Spotsylvania County, Virginia, neighboring property owners and community members have filed complaints with the county's board of zoning appeals related to the development of a 6,300 acres utility-scale solar facility.

Aside from the land, the supply chain organization for the solar industry will be challenged to meet the level of solar generation in Alternative Plans B through D. This includes both equipment suppliers and construction contractors. Specifically, world-wide panel manufacturers will need to ramp up production as the demand for solar generation increases both inside the Company's service territory and across the United States. Additionally, qualified construction contractors for building utility-scale solar facilities will need to expand and train a large a labor force. Utilizing a skilled vendor to construct the solar facilities will be an important factor going forward, as the land available for future solar development is expected to be less optimal, requiring more design and engineering work to meet output targets.

Chapter 6: Generation – Demand-Side Management

This chapter provides a description of the DSM planning process, and an overview of approved, proposed, and rejected DSM programs. See Section 4.1.3 for discussion of how the Company adjusted the load forecasts used in this 2020 Plan to account for energy efficiency targets. This chapter also provides the energy efficiency-related analysis required by the GTSA.

In this 2020 Plan, there is a total reduction of 1,120 GWh by 2020 in DSM-related savings. By 2025, there are 3,459 GWh of reductions included in the PLEXOS modeling for this 2020 Plan. Projected energy savings include reductions from identified sources (*i.e.*, DSM programs approved by and proposed to the SCC), as well as unidentified sources (*i.e.*, "generic" DSM as discussed below). For modeling purposes, neither the identified nor the unidentified sources included free-ridership effects. If these sources had included free-ridership effects, the reductions by 2020 and 2025 would be 945 GWh and 3,028 GWh, respectively. Projected savings attributable to DSM programs in 2025 are shown in Figure 6.1.

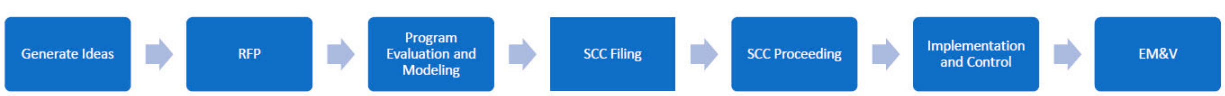
There are several drivers that will affect the Company's ability to meet the current level of projected energy and demand reductions, including the cost-effectiveness of the DSM programs when filed, the SCC and NCUC approval of newly filed programs, the continuation of existing programs, the final outcome of proposed environmental regulations, the full implementation of AMI and the customer information platform through the Company's Grid Transformation Plan, and customers' willingness to participate in approved DSM programs.

<u>Figure 6.1 - DSM Program Projected Savings By 2025</u>

	Program	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Phase I	Air Conditioner Cycling Program	54	-	Approved / Approved
	Residential Low Income Program	2	8	Completed / Completed
	Residential Lighting Program	-	-	
	Commercial Lighting Program	-	-	Closed / Closed
	Commercial HVAC Upgrade	1	4	
Phase II	Non-Residential Distributed Generation Program	12	1	Extension Approved / Rejected
	Non-Residential Energy Audit Program	-	-	Completed /Completed
	Non-Residential Duct Testing and Sealing Program	8	81	
	Residential Bundle Program	7	29	
	Residential Home Energy Check-Up Program	*1*	*10*	
	Residential Duct Sealing Program	*1*	*2*	
	Residential Heat Pump Tune Up Program	-	-	
	Residential Heat Pump Upgrade Program	*4*	*17*	
Phase III	Non-Residential Window Film Program	4	4	
	Non-Residential Lighting Systems & Controls Program	19	115	
	Non-Residential Heating and Cooling Efficiency Program	7	34	
Phase IV	Income and Age Qualifying Home Improvement Program	2	17	Extension Approved/Approved
	Residential Appliance Recycling Program	-	-	Completed
Phase V	Small Business Improvement Program	16	90	Approved/Approved
	Residential Retail LED Lighting Program (NC only)	1	7	No Plans/Completed
Phase VI	Non-Residential Prescriptive Program	8	21	Approved/Approved
Phase VII	Residential Efficient Products Marketplace Program	6	436	
	Non-Residential Lighting Systems & Controls Program	9	43	
	Residential Appliance Recycling Program	4	28	
	Non-Residential Heating and Cooling Efficiency Program	9	42	
	Non-Residential Window Film Program	2	9	
	Residential Home Energy Assessment Program	15	88	
	Non-Residential Office Program	2	26	
	Non-Residential Small Manufacturing Program	3	15	
	Residential Customer Engagement Program	15	51	Approved/Future
	Residential Smart Thermostat Management Program (DR)	83	-	
	Residential Smart Thermostat Management Program (EE)	4	23	
Phase VIII	Non-Residential Midstream EE Products	12	19	Proposed/Future
	Non-Residential New Construction	5	21	
	Residential EE Kits	3	38	
	Residential Home Retrofit	6	21	
	Residential Manufactured Housing	4	17	
	Multifamily Program	21	68	
	HB 2789 HVAC Component	6	19	
	Residential New Construction	17	32	
	Non-Residential Small Business Improvement Enhanced	14	47	
	Residential Electric Vehicle EE/DR	6	2	
	Residential Electric Vehicle Peak Shaving	1	0	

6.1 DSM Planning Process

The Company has historically used the following process related to its DSM programs:



The GTSA established the DSM stakeholder group, which helps to generate program ideas. The Company takes those ideas and develops them into more concrete program parameters, which are then compiled into an RFP of candidate program designs and implementation services sent to qualified vendors. The Company develops assumptions for new DSM programs by engaging vendors through a competitive RFP process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. The Company generally prefers, to the extent practical, that the program design vendor is ultimately the same vendor that implements the program in order to maintain as much continuity as possible from design to implementation.

Once proposals through an RFP process are received, the Company's energy conservation group works with its supply chain group to systematically review the proposals. Program designs are reviewed for responsiveness to the RFP, practicality of the design, technology requirements, staffing plan, marketing plan, reasonableness of the measures proposed, overlap with existing measures, cost reasonableness, previous experience, work history with the Company, expected ability to deliver the services proposed, and ability of the proposing firm to comply with the Company's terms and conditions, data protection requirements, and financial requirements. Proposals must contain detailed information regarding measure load profiles and market penetration projections in a specific format that allows modeling of the program as a demand side resource when compared against other resources, including supply-side resources.

Candidate designs that are judged to be reasonable, based on preliminary review, are evaluated for cost-effectiveness from a multi-perspective approach using four of the standard tests from the California Standards Practice Manual: (i) the Participant Test, (ii) Utility Cost Test, (iii) Total Resource Cost ("TRC") Test, and (iv) Ratepayer Impact Measure Test. Each test uses the NPV of costs and benefits. Tests are conducted at a program level.

PLEXOS does not have the ability to conduct cost-benefit evaluations for DSM within the model itself, leading to the need for an additional model, tool, or process. For this reason, the Company has continued its use of Strategist for DSM evaluations using consistent data between the models. The inputs into Strategist are consistent with those in PLEXOS for the 2020 Plan. The Company looks at the results of all of the cost-benefit test scores, as well as NPV results, to evaluate whether to file for regulatory approval of a potential program or program extension.

If the programs are cost effective based on the modeling results, or otherwise legislatively deemed to be in the public interest for policy reasons, the programs are then filed with the SCC for approval. The SCC approval process lasts approximately eight months. For the programs that are approved, the Company works with the RFP suppliers to finalize a contract for full implementation of the program. Once all details are finalized, a new DSM program can be launched for participation by eligible customers.

Finally, the Company conducts evaluation, measurement and verification of all DSM programs and provides reports to the SCC each May for the prior calendar year on specific program metrics, including participation, spending, and energy and demand savings.

6.2 Approved DSM Programs

Appendix 6A provides program descriptions for the currently active DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and its plans to achieve each program's penetration goals. Appendices 6B, 6C, 6D, and 6E provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved program.

In July 2019, the Company filed for NCUC approval of the (i) Residential Home Energy Assessment Program, (ii) Residential Efficient Products Marketplace Program, (iii) Residential Appliance Recycling Program, (iv) Non-Residential Window Film Program, (v) Non-Residential Small Manufacturing Program, (vi) Non-Residential Office Program, (vii) Non-Residential Lighting Systems & Controls Program, and (viii) Non-Residential Heating and Cooling Efficiency Program. In November 2019, the NCUC issued its Final Order approving all eight programs.

The Company also currently offers one DSM pricing tariff, the standby generation ("SG") rate schedule, to enrolled commercial and industrial customers in Virginia. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed. Two customers are on SG in Virginia. The SG rate schedule provides 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 the average capacity generated during a billing month when SG is requested. 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. Figure 6.2.1 provides estimated load response data for summer/winter 2019.

Figure 6.2.1 - Estimated Load Response Data

Tariff	Summer 2019		Winter 2019	
	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	19	2	0	0

The Company modeled this existing DSM pricing tariff over the Study Period based on historical data from the Company's customer information system. Projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future.

6.3 Proposed DSM Programs

On December 3, 2019, the Company filed for SCC approval in Case No. PUR-2019-00201 of eleven new DSM programs and extension of one existing program. The eleven proposed programs in Phase VIII are:

- Residential Electric Vehicle (EE & DR);
- Residential Electric Vehicle (Peak Shaving);

- Residential Energy Efficiency Kits;
- Residential Home Retrofit;
- Residential Manufactured Housing;
- Residential New Construction;
- Residential/Non-Residential Multifamily;
- Non-Residential Midstream Energy Efficient Products;
- Non-Residential New Construction;
- Small Business Improvement Program Enhanced; and
- HB 2789 Heating and Cooling/Health and Safety.

In addition, the Company filed for an extension of the existing Air Conditioner Cycling Program and expedited approval to launch three of the Phase VII programs. The SCC must issue its Final Order in Case No. PUR-2019-00201 by August 2020.

Through House Bill No. 2789 from the 2019 Regular Session of the Virginia General Assembly, the Company is required to seek approval of a three-year rebate program targeting low-income, elderly, and disabled customers. The program would incentivize energy conservation measures that reduce residential heating and cooling costs and enhance the health and safety of residents (at least $25 million available in rebates). Another program targeting participants in the above-described program must incentivize installation of solar equipment (not to exceed $25 million). In December 2019, the Company filed for approval of the energy efficiency component of the rebate program. The solar stakeholder group continues to develop the solar component of this program.

Appendix 6F provides program descriptions for the proposed DSM programs. Appendices 6G, 6H, 6I and 6J provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each proposed program.

6.4 Future DSM Initiatives

The Company is currently conducting an appliance saturation study and, once completed, will begin a new DSM market potential study within the Company's service territory. This market potential study will provide additional guidance regarding what additional DSM measures are achievable.

As noted in Section 6.1, during the first and second quarter of each year, the Company conducts an RFP process to solicit designs and recommendations for a broad range of DSM programs. The Company anticipates continuing this process for the foreseeable future. Within this process, detailed proposals are requested for programs that include measures identified in the most recent DSM Potential Study, as well as other potential cost-effective measures based upon current market trends.

Load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations for the Company in determining which DSM resources to deploy in the future. The use of these DSM resources largely depends on the circumstances and cannot be prescribed in any definitive manner. The Company will continue to identify and seek approval to implement DSM programs that are cost effective or meet public policy goals.

As to cost-effective DSM available to respond to the growth of the winter peak, the Company's Distributed Generation Program is currently available to eligible non-residential customers in Virginia and provides dispatchable demand savings during winter periods to non-residential customers who meet participation requirements based upon size. The Company currently has a demand response residential thermostat control program pending approval in Virginia, which would also provide winter demand and energy savings. Further, the Company's other proposed DSM programs noted in Section 6.3 address both summer and winter peaks as well as energy requirements. While demand response programs can be used to reduce peak periods explicitly, energy efficiency programs can also provide reductions during winter hours. The Company is also participating in a stakeholder process required by the GTSA to help it identify potential opportunities for future energy efficiency and demand response programs. This effort will hopefully lead to future DSM initiatives that will address both summer and winter peak hours.

Appendices 6K and 6L provide the system-level coincidental peak savings and energy savings for future undesignated EE programs.

6.5 Rejected DSM Programs

The Company rejected the following programs as part of the 2019 DSM process: (i) Non-Residential Agricultural EE, (ii) Non-Residential Strategic Energy Management, and (iii) Non-Residential Telecommunications Optimization. A list of these and other rejected DSM programs from prior integrated resource planning cycles is shown in Appendix 6M. Rejected programs may be re-evaluated and included in future DSM portfolios.

6.6 GTSA Energy Efficiency Analysis

Enactment Clause 18 of the GTSA required the Company to "incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity."

The Company is committed to meeting state energy goals, which is why the Company offers energy conservation programs to help customers save energy and maximize savings while also reducing emissions and the Company's carbon intensity. The GTSA sets the target of proposing $870 million of spending on energy efficiency between 2018 and 2028. Of this amount, the VCEA directs that at least 15% be for programs aiding low-income, elderly, veteran, and disabled customers. The VCEA further sets the target of reaching 5% energy efficiency savings (based on 2019 jurisdictional electricity sales) by 2025.

The Company has determinedly sought approval of new DSM programs from the SCC—including 22 new programs in the last two years—to meet these targets. The Company is also actively involved in regular stakeholder meetings to generate new program concepts and then utilizes an annual solicitation of new measures and program re-designs from expert vendors within the industry.

The Company considers the stakeholder forum, which provides transparency and inclusivity in the process, to represent the best opportunity to develop a long-term plan for energy efficiency measures that will ultimately achieve the DSM policy goals set by the Commonwealth.

Enactment Clause 18 of the GTSA also directed that utility considerations of energy efficiency within its long-term plan shall include analysis of the following:

- Energy efficiency programs for low-income customers in alignment with billing and credit practices;
- Energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions;
- Programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers;
- Options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers;
- The extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states;
- An analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and
- Other issues as may seem appropriate.

6.6.1 Considerations for Certain Customers Groups and Options for Combining Distributed Generation, Energy Storage, and Energy Efficiency

The Company's existing Residential Income and Age Qualifying Home Improvement Program provides in-home energy assessments and installation of select energy-saving products at no cost to eligible participants. The Program is available to qualified customers in the Company's Virginia service territory. The Program conforms to the Virginia Department of Housing and Community Development qualification guidelines, which is currently set at 60% state median income. It is also available to customers who are 60 years or older with a household income of 120% of the state median income. Notably, the Company has proposed changing eligibility for this and future income-based programs to use area median income to allow greater eligibility among participants living in higher-income areas of the state that may still be in need. The Program is available to qualified individuals living in single-family homes, multifamily homes, and mobile homes. Based on evaluation, measurement and verification, however, this Program's participants have largely—more than 90%—come from multifamily living situations.

Additionally, a special subgroup focused on low income DSM program improvements is meeting as part of the stakeholder process and making valued suggestions for future improvements that will result in better alignment with the state's federally funded program. The Company has and will continue to work with the Department of Housing and Community Development to establish alignment with programs where helpful and beneficial.

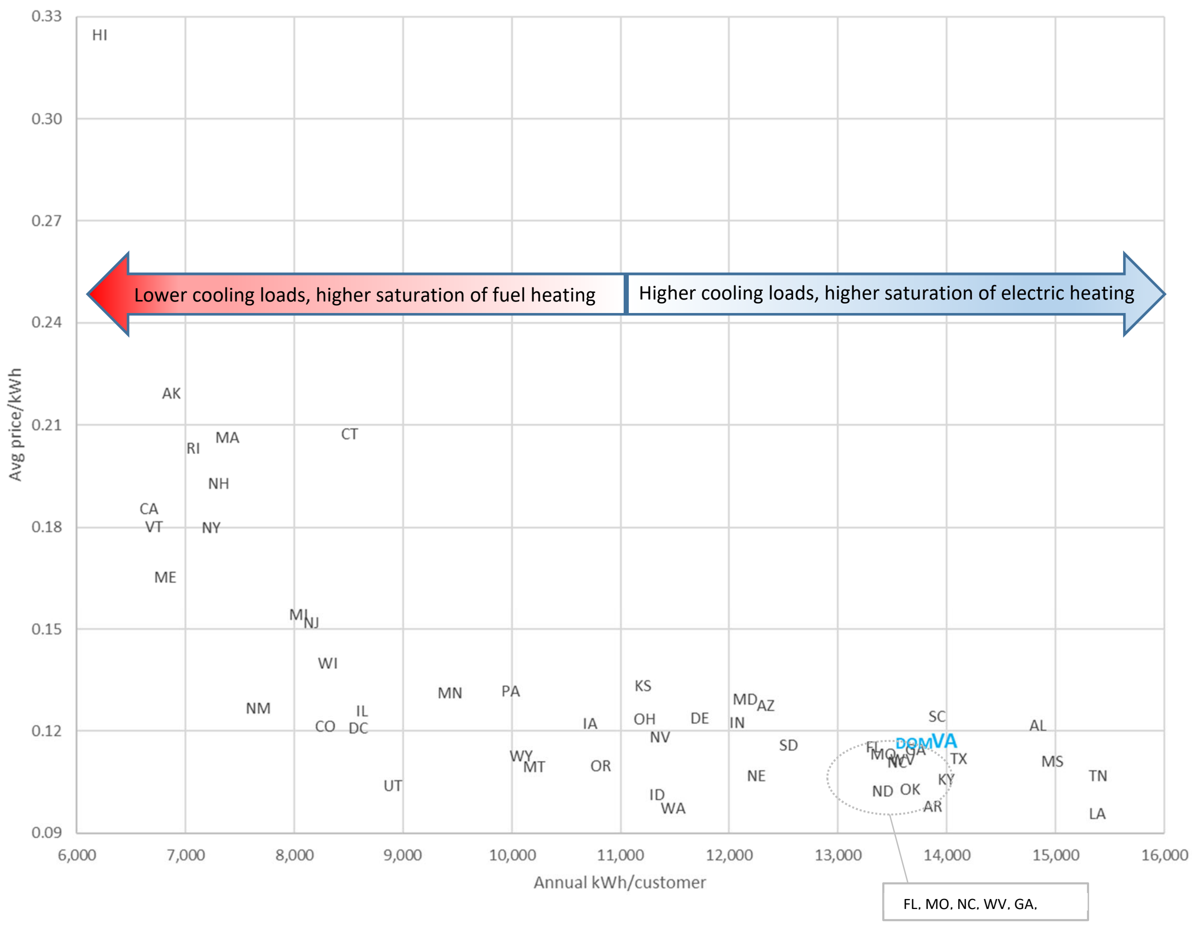
Finally, in December 2019, the Company requested SCC approval of the first component of the House Bill 2789 (Heating and Cooling/Health and Safety) Program as part of its DSM Phase VIII proposal. Virginia House Bill 2789 requires that a petition be submitted for a program for income qualifying, elderly and disabled individuals consisting of two components. The first component would offer incentives for the installation of measures that reduce residential heating and cooling costs and enhance the health and safety of residents, including repairs and improvements to home heating and cooling systems and installation of energy-saving measures in the house, such as insulation and air sealing. The second component would offer incentives to participants of the first component for the installation of equipment to generate electricity from sunlight. The Company expects to request approval of the second component associated with solar generation equipment in a future filing.

6.6.2 Electricity Rate and Consumption Comparison

Electricity bills are driven by a combination of electricity rates and electricity consumption. The following charts show where each state and the Company falls by electricity rate and consumption.

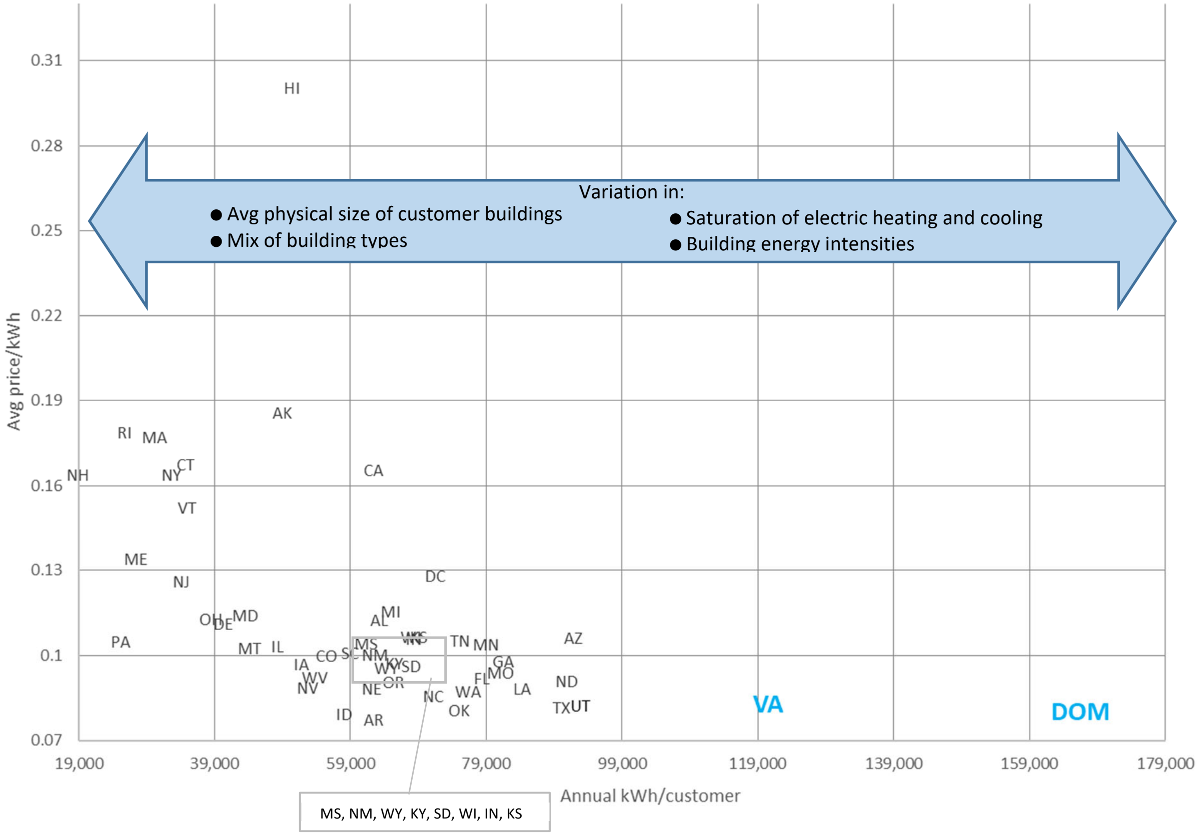
In the residential sector, the Company and Virginia as a whole fall within a cluster of mostly southern states with below-average rates and relatively high consumption. The consumption level reflects a high saturation of electric heating equipment compared to other parts of the U.S., paired with high cooling loads.

Figure 6.6.2.1 – States by Residential Average Price per kWh and Consumption per Household



In the commercial sector Virginia is an extreme outlier in consumption per customer, averaging more than 120,000 kWh per year. The Company is one of three utilities in Virginia with average commercial consumption over 100,000 kWh per year; the others are the City of Harrisonburg and Virginia Tech Electrical Services. In contrast, the lowest average commercial consumption belongs to Community Electric Cooperative at less than 14,000 kWh per commercial customer, comparable to a home. The primary drivers of commercial consumption are the size of the customer (building square feet, number of employees) and the type of building activity. Denser urban areas tend to have larger commercial buildings and therefore higher average commercial consumption, and the Company's service territory captures many of Virginia's densest urban areas. The Company also has a high concentration of data centers among its commercial customers. Data centers are extremely energy intensive, as the densely packed computing equipment they contain produces waste heat that drives high space cooling loads. Because of the extreme differences among commercial customers, building efficiencies are typically compared based on energy intensity (energy use per square foot) and only among similar building types (offices with offices and restaurants with restaurants).

Figure 6.6.2.2 – States by Average Commercial Price per kWh and Average Consumption per Commercial Customer



6.6.3 *National Comparison of Primary Fuel Sources for Generation*

The Company engaged DNV GL Energy Insights U.S.A. ("DNV GL") to analyze fuel source for generation, as well as the additional metrics referred to in the legislation. This analysis is provided in Appendix 6N.

6.6.4 *Other Relevant Issues for Energy Efficiency Analysis*

DNV GL, on behalf of the Company, also regularly assesses both the current stock of appliances through an appliance saturation study, and the potential for electric energy (kWh) and demand (kW) savings from Company-sponsored DSM programs through a Market Potential Study of both residential and commercial customers. The most recent iteration of this process is currently underway and results are expected by late 2020. The results will include

- Estimates of the magnitude of potential savings on an annual basis;
- Estimates of the costs associated with achieving those savings; and
- Calculations of the cost effectiveness of the measures based on the estimates above from a TRC perspective assuming PJM market price estimates.

The Company and DNV GL conducted previous Market Potential Studies in 2015 and 2017; the 2017 Market Potential Study was updated in 2018 to reflect changes to eligibility for commercial customers due to the GTSA. Appliance Saturation Studies and Residential Conditional Demand Analyses were conducted in 2013 and 2016, and included mail and electronic surveys of residential and commercial customers.

The Market Potential Studies estimate three basic types of energy efficiency potential:

- Technical potential: The complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
- Economic potential: The technical potential of those energy efficiency measures that are cost-effective when compared to supply-side alternatives.
- Achievable program potential: The amount of savings that would occur in response to specific program funding, marketing, and measure incentive levels. In this study, the Company looked at the potential available under two funding scenarios—50% incentives and 75% incentives.

The Company, through its DSM stakeholder process, uses the information contained in the Market Potential Studies to help develop ideas for potential DSM programs to include measures that may be cost beneficial. The most recent Market Potential Study is typically released with a Company solicitation for DSM programs.

6.7 Overall DSM Assessment

At the end of the Planning Period (*i.e.*, 2035), energy reductions projected for the identified DSM programs are approximately 1,373 GWh. This compares to 1,276 GWh identified in the 2019 Update, or an approximately 8% increase in energy reductions. The majority of the increase in energy reductions is attributed to the proposed Phase VIII DSM programs included in the 2019 Virginia DSM filing.

The capacity reductions at the end of the Planning Period for the identified DSM programs are 383 MW in this 2020 Plan. This compares to 405 MW in the 2019 Update, or an approximately 5% decrease in demand reductions. This decrease is largely attributable to (i) the Non-Residential Prescriptive Program not yet realizing adoption of high energy and high capacity reduction measures; and (ii) corrected design assumptions for the Residential Thermostat Programs.

In this 2020 Plan, the unidentified DSM resources are presented as an unidentified generic block of energy efficiency reductions priced at $200/MWh to meet the GTSA and VCEA requirements, as explained in Section 4.1.3. For comparison, in the 2019 Update, the Company included an unidentified generic block of energy efficiency reductions to meet the requirements of the GTSA only.

See Section 4.1.3 for a discussion of the energy efficiency reductions used as adjustments to the load forecast in this 2020 Plan. Figures 4.1.3.1 and 4.1.3.2 show these energy efficiency energy and capacity adjustments, respectively.

Figure 6.7.3 presents a comparison of the Company's expected demand-side management costs relative to expected supply-side costs. The costs are provided on a levelized cost per MWh basis for both supply- and demand-side options. The supply-side options' levelized costs are developed by determining the revenue requirements, which consist of the dispatch cost of each of the units and the revenue requirement associated with the capital cost recovery of the resource. The demand-side options' levelized cost is developed from the cost-benefit runs. The costs include the yearly program cash flow streams that incorporate program costs, customer incentives, and evaluation, measurement, and verification costs. The NPV of the cash flow stream is then levelized over the Planning Period using the Company's weighted average cost of capital. The costs for both types of resources are then sorted from lowest cost to highest cost and are shown in Figure 6.7.3.

Figure 6.7.3 – Comparison of per MWh Costs of Selected Generation Resources

Comparison of per MWh Costs of Selected Generation	Capacity Factor	Cost ($/MWh) no RECs	Cost ($/MWh) with RECs
Residential Efficient Products Marketplace Program	n/a	$11	n/a
Non-Residential Heating and Cooling Efficiency Program	n/a	$30	n/a
Residential EE Kits	n/a	$33	n/a
Multifamily Program	n/a	$33	n/a
Small Business Improvement Program	n/a	$37	n/a
Non-Residential Window Film Program	n/a	$43	n/a
Residential Home Retrofit	n/a	$44	n/a
Residential Customer Engagement Program	n/a	$46	n/a
Non-Residential Lighting Systems and Controls Program	n/a	$48	n/a
Non-Residential Office Program	n/a	$55	n/a
Solar	25%	$58	$49
Non-Residential Small Business Improvement Enhanced	n/a	$60	n/a
Residential Manufactured Housing	n/a	$60	n/a
CC - 3X1	80%	$61	n/a
Non-Residential Small Manufacturing Program	n/a	$61	n/a
Residential Home Energy Assessment Program	n/a	$61	n/a
Residential Smart Thermostat Management Program (EE)	n/a	$62	n/a
Residential Appliance Recycling Program	n/a	$64	n/a
CC - 2X1	80%	$64	n/a
Non-Residential Midstream EE Products	n/a	$65	n/a
Residential New Construction	n/a	$67	n/a
CC - 1X1	80%	$70	n/a
CC - 3X1 w/ CCS	80%	$71	n/a
Non-Residential New Construction	n/a	$74	n/a
CC - 2X1 w/ CCS	80%	$80	n/a
Wind - Onshore	40%	$82	$73
Greenfield Nuclear SMR (Unit 1)	92%	$92	n/a
Wind - Offshore	42%	$101	$92
CT	20%	$101	n/a
CT (Aero)	20%	$126	n/a
Large Nuclear	92%	$139	n/a
Biomass	90%	$185	$176
HB 2789 HVAC Component	n/a	$188	n/a
Fuel Cell	90%	$193	n/a
VCHEC w/ CCS	50%	$195	n/a
Solar & CT (Aero)	20%	$202	$193
Energy Storage - NREL	15%	$252	$252
Residential Income and Age Qualifying Home Improvement Progran	n/a	$258	n/a
SCPC w/ CCS	50%	$327	n/a
Non-Residential Prescriptive Program	n/a	$334	n/a
Residential Electric Vehicle EE	n/a	$342	n/a
Battery Generic (30 MW)	15%	$349	n/a
Pump Storage (300 MW)	15%	$624	n/a

Notably, the Company does not use levelized costs to screen DSM programs. DSM programs also produce benefits in the form of avoided supply-side capacity and energy cost that should be netted against DSM program cost. The DSM cost-benefit tests are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options, and are the methods the Company uses to screen DSM programs.

Chapter 7: Transmission

This chapter provides an overview of the transmission planning process, as well as a list of current and future transmission projects. In addition, this chapter provides the results of the system reliability analysis performed to assess the potential effect of retiring all generating units that emit CO_2 as a byproduct of combustion by 2045.

7.1 Transmission Planning

The Company's transmission system is responsible for providing transmission service: (i) for redelivery to the Company's retail customers; (ii) to Appalachian Power Company, Old Dominion Electric Cooperative ("ODEC"), Northern Virginia Electric Cooperative, Central Virginia Electric Cooperative, and Virginia Municipal Electric Association for redelivery to their retail customers in Virginia; and, (iii) to North Carolina Electric Membership Corporation and North Carolina Eastern Municipal Power Agency for redelivery to their customers in North Carolina (*i.e.*, collectively, the DOM Zone). Also, several independent power producers ("IPPs") are interconnected with the Company's transmission system and are dependent on the Company's transmission system for delivery of their capacity and energy into the PJM market.

The Company is part of PJM, which is currently responsible for ensuring the reliability of, and coordinating the movement of, electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The Company also is part of the Eastern Interconnection transmission grid, meaning its transmission system is interconnected, directly or indirectly, with all of the other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. All of the transmission systems in the Eastern Interconnection are dependent on each other for moving bulk power through the transmission system and for reliability support.

The Company's transmission system is designed and operated to ensure adequate and reliable service to 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. Federally-mandated NERC Reliability Standards constitute minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. Moreover, the Energy Policy Act of 2005 mandates that electric utilities follow these NERC Reliability Standards and imposes fines for noncompliance of approximately $1.3 million per day per violation.

The Company participates in numerous regional, inter-regional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is a member of PJM; 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 5-year and a 15-year outlook. The Company is actively involved in supporting the PJM RTEP process.

The Company also evaluates its ability to support expected customer growth through its internal transmission planning process. The results of this evaluation indicates if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate. If the need is confirmed, then the Company seeks approval for the transmission improvements from the appropriate regulatory body.

Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. The Company coordinates with neighboring utilities to maintain adequate levels of transfer capability to facilitate economic and emergency power flows.

7.2 Existing Transmission Facilities

The Company has approximately 6,800 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.

7.3 Transmission Facilities Under Construction

A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 7A. Through participation in the PJM RTEP as well as regional, inter-regional, and sub-regional studies described in Section 7.1, the Company annually assesses the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons.

7.4 Future Transmission Projects

Appendix 3D provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM as part of the RTEP process.

7.5 Transmission System Reliability Analysis

In order to understand the possible system reliability implications of Alternative Plans C and D—both of which retire all Company-owned carbon-emitting generation in 2045 resulting in close to zero CO_2 emissions from the Company's fleet in 2045—the Company performed a power flow analysis by developing a base power flow case and three different scenarios. To conduct this analysis, the Company made numerous simplifying assumptions. Standard transmission planning analysis is conducted in a near-term horizon (years 1 to 5) and a long-term horizon (years 6 to 10). The reliability analysis conducted for the evaluations of Alternative Plans C and D is 15 years and 30 years into the future, which is significantly longer than standard long-term reliability assessment timeframes. Because the timeframe for analysis was for an additional twenty years, the analysis was unable to account for the significant changes to the transmission systems topology (*e.g.*, transmission lines, load, generation resources) both in the DOM Zone and the Eastern Interconnection that will occur during this timeframe. In addition, the planning model used in this analysis models the Eastern Interconnection, which encompasses all the transmission facilities, generation resources and system loads from essentially the Rocky Mountains to the East Coast. This model incorporates the 2023 year topology of the transmission system and was the base case used for other model changes to perform the future year assessments. The only loads adjusted in this model for the future year assessments were in the DOM Zone, and were scaled up uniformly to levels projected for summer 2035, winter 2035 and summer 2050 based on the growth rates shown in 2020 PJM Load Forecast. The generation resources located in the DOM Zone were modified as discussed below.

In all power flow cases developed for this reliability analysis, approximately 900 MW of ODEC gas-fired generation and approximately 2,900 MW of IPP gas-fired generation was modeled on-line on the Company's system, as it is the Company's understanding that the VCEA does not require the retirement of these generating units. Additionally, approximately 21,000 MW of solar and approximately 5,400 MW of offshore wind were modeled as per PJM RTEP protocols (*i.e.*, PJM capacity factors used to calculate capacity injection rights).

The four power flow cases modeled all Company-owned carbon-emitting generation in 2045 as off-line (retired), except as modified below:

- Power Flow Case 1 (base case): Warren, Greensville and Brunswick County gas-fired CC generating units remained in service for each year under study.
- Power Flow Case 2: Warren and Greensville gas-fired CC generating units remained in service for each year under study.
- Power Flow Case 3: Warren gas-fired CC generating unit remained in service for each year under study.
- Power Flow Case 4: Brunswick, Greensville, and Warren County gas-fired CC generating units off-line (retired) for each year under study.

The initial results of the 2035 and 2050 analysis of all four power flow cases identified NERC reliability deficiencies on twenty-six 115 kV lines, thirty-two 230 kV lines, six 500 kV lines, and eleven transmission transformers that would need to be resolved to avoid NERC violations. The results of these studies are in no way a substitution for the actual generation retirement analysis and generation queue analysis that any generator must follow as part of PJM's RTEP process, especially if they are or want to be considered a PJM capacity resource.

Based on the summer 2035, winter 2035 and summer 2050 peak load runs described above, a first contingency incremental transfer capability analysis was performed. This analysis indicated that for Alternative Plans C and D, the Company's transmission system is not capable of importing the amounts of energy required without the development of significant interregional transfer capability or the addition of significant generation resources (as discussed below) in the DOM Zone, which would need to be directly connected to the Company's transmission system in order to be available to serve both the peak winter and peak summer loading conditions. The interregional transfer capability would be added by the addition of new multi-state transmission lines ("Interregional Transmission Lines"). These multistate lines would have to interconnect with generation resources located in the PJM system and terminating in major load centers in Virginia, like Northern Virginia, the Richmond metropolitan area, and the Hampton Roads metropolitan area. These Interregional Transmission Lines could be either alternating current ("AC") or direct current ("DC") transmission lines. The Trail Project, built in 2006 at a cost of approximately $1.2 billion and going from Pennsylvania to West Virginia to Virginia, was the most recent type of interregional transmission facility built on the PJM system. Further, additional generation resources located in the DOM Zone would be needed in order to address the amount of intermittent renewable resources being added to the system in the Planning Period. These generation resources would need to be quick start and capable of continued operation that is not impacted by weather conditions.

As shown in the Figure 5.6.2.2, Alternative Plans A, B, C, and D require the Company's transmission system to be able to import 5,200 MW to serve the DOM Zone load in the Planning Period, and between 5,200 MW (Alternative Plans A and B) and 10,400 MW (Alternative Plans C and D) to be able to serve DOM Zone load in the Study Period. The transmission impacts related to each of the Alternative Plans is summarized below.

- Plan A – Normal transmission planning expected with no additional transmission level import increase required to maintain 5,200 MW of import capability. Since Alternative Plan A has a smaller portion of its generation resources that are impacted by weather conditions (*i.e.*, renewable generation) and fewer generation retirements, this alternative still reflects the DOM Zone operating in a firm operational state not dependent upon weather conditions.
- Plan B – Normal transmission planning expected with no additional transmission level import increase costs required to maintain 5,200 MW of import capability. While Alternative Plan B has a larger amount of solar, energy storage, and offshore wind resources added as compared to Alternative Plan A, Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues as compared to Alternative Plan A and, therefore, construction of Interregional Transmission Lines are not anticipated.
- Plan C – This alternative will require additional transmission level import increase costs in order to construct Interregional Transmission Lines to obtain 10,400 MW of import capability. Alternative Plan C has a larger amount of solar, energy storage, and offshore wind resources added as compared to Alternative Plan A, as well as significantly more generation retirements of the existing DOM Zone generation fleet as compared to Alternative Plan A. As a result, four Interregional Transmission Lines would need to be constructed at a placeholder estimated cost of approximately $8.4 billion.
- Plan D – This alternative will require additional transmission level import increase costs in order to construct Interregional Transmission Lines to obtain 10,400 MW of import capability. While Alternative Plan D has a larger amount of solar resources added than Alternative Plan C and a larger amount of energy storage and offshore wind resources added as compared to Alternative Plan A, based on capacity factors, there is no change in the amount of generation retirements of the existing DOM Zone generation fleet as

compared to Alternative Plan C. As a result, four Interregional Transmission Lines would need to be constructed at a placeholder estimated cost of $8.4 billion.

Importantly, this analysis is high level, preliminary and made with numerous simplifying assumptions. Extensive additional analysis is needed over time. For example, this analysis does *not* address analysis and costs that arise from the loss of traditional rotating synchronous generators. Transitioning from traditional rotating synchronous generation to inverter-based (*i.e.*, intermittent renewable) solar- and wind-powered resources and the addition of large-scale energy storage facilities (*e.g.*, battery and pumped storage) will change the very nature of the electric grid, and requires a fundamental reevaluation of the electric grid for based on two primary results:

- The loss of dispatchable, or controllable generation and challenges associated with the addition of large-scale energy storage facilities; and
- The loss of stored kinetic energy.

Traditional generation sources are large rotating turbines usually powered by either heated steam or falling water, and therefore these generation sources and their output can be both predicted and controlled. Controlling the output of these generators is achieved by regulating the input supply of water or steam. Inverter-based generation relies on resources (*e.g.*, the sun and the wind) that cannot be controlled or predicted in this way. As a result, these generation sources are not dispatchable in response to changes in electrical demand and can be unavailable to serve peak loading conditions. This is the first fundamental difference that must be addressed. Currently, one of the ways PJM manages this is by calculating a dependable capacity rating for intermittent resources. This dependable capacity rating is what is required to be used in transmission planning analysis as part of PJM's FERC-approved RTEP process. While this capacity rating is designed to match the average output of intermittent resources in a region during peak summer loading conditions, it misses the range of conditions that the electric system may have to withstand, such as timeframes when intermittent generation output is close to 100% of its nameplate rating or during winter loading conditions when, for example, the solar generation output is essentially zero. The addition of large-scale storage facilities can support these challenges with solar- and wind-based resources, but these storage facilities will create new challenges themselves that must be addressed.

One essential challenge with the addition of large-scale storage facilities on the Company's system is that it will result in a significant increase in peak system load requirements. Storage will primarily be discharged (*i.e*., behaving like a generator) at night time to serve system load when solar output across the system is zero. Therefore, the storage facilities will charge (*i.e*., behaving like a load) during daylight hours, contributing to the peak system load conditions that occur across the daylight hours, like a summer peak load. For example, approximately 9,930 MW of storage could potentially be added as system load in Alternative Plans C and D, significantly increasing the peak load that the Company's transmission system must reliably serve consistent with NERC reliability criteria. It is also critical to note that the storage facilities must be charged up and available to serve the night time load; therefore, during daylight hours the uses of these storage facilities will be very limited, as the primary use must be charging up to be ready for the night time load.

The loss of stored kinetic energy is a more technical concern. The rotation of traditional turbines creates a reservoir of kinetic energy that automatically provides support when problems arise and balances the myriad of instantaneous discrepancies between generation and load at any moment in time. Inverter-based generation does not provide such a reservoir. This correlates to several areas of study that have not historically been necessary to consider during transmission system planning studies and analyses, but will be essential going forward. Today, these include the areas of study listed below, but the Company expects this list to grow and evolve over time.

- Inertia and frequency control;
- Short-circuit system strength;
- Power quality;
- Reactive resources and voltage control;
- System restoration and black start capabilities;
- Grid monitoring and control capabilities;
- Energy storage requirements; and
- High-voltage direct current ("HVDC").

7.5.1 Inertia and Frequency Control

Electrical inertia is the capacity of a system to resist changes in electrical frequency, which is the real-time balance between generation and load. Electrical inertial response acts to overcome an immediate imbalance between power supply and demand. Electrical inertia is directly related to the reservoir of stored kinetic energy inherent to the traditional rotating synchronous generators on the system. Inertia is what allows the electric grid to control the frequency deviations that occur all the time, which are caused by events such as load changes, transmission and distribution outages, generation shedding, and system instability. Inverter-based solar- and wind-powered resources have no rotating components and, as a result, typically do not contribute to system inertia. This can lead to significant problems in managing system frequency, leading to a less reliable electric grid under high penetration of inverter-based generation resources. This problem must be studied and resolved over time with new frequency control strategies and technologies that must be designed, tested, and implemented on the system. This could include new technologies and concepts that are being explored and researched now, including the emulation of inertia in inverter control systems.

7.5.2 Short-circuit System Strength

A short circuit, also known as a fault, is an undesirable electrical connection, such as a tree branch falling across electrical lines. When these short circuit events occur, it is critical to remove from service the faulted energized equipment as quickly as possible to ensure personnel and public safety, prevent or reduce equipment failure, and maintain the stability of the electric grid. This is done today in the timeframe of milliseconds to seconds by protection and control systems that are comprised of relays, circuit breakers, reclosers, and fuses installed across the entire system. In today's electric grid, a short circuit typically results in a spike in electrical current to that point and depressed voltage around the location of the fault. This occurs today because traditional rotating synchronous generators supply this significant amount of current during short-circuit events. The protection and control systems in operation today, across the entire system in generation plants, transmission and distribution substations, distribution circuits, and even inside customer facilities and homes, are all primarily designed to remove short circuit events by the detection of very high current.

Inverter-based generation resources (*e.g.*, solar and wind) do not provide any significant increase in current during short circuit events; rather they provide either no change in current or only a very nominal amount during the short circuit events. As traditional rotating synchronous generators are retired and replaced with more and more inverter-based generation, it is expected that the system will experience a fundamental change in short circuit behaviors across all levels of the grid, specifically lowering the currents and strength of short circuits. This will cause the Company's existing protection and control systems installed across the entire system to have major challenges in detecting these short circuit events and protecting the system, personnel, and the public. This problem must be studied and resolved over time, looking into new technologies that must be designed, tested, and implemented, such as new grid devices that provide fault current or new protection and control schemes on generation, transmission, distribution, and customer facilities that are have new designs and operating characteristics.

7.5.3 Power Quality

All standards for grid-tied systems set demands on the quality of the power supply. These systems have previously drawn from the centralized reservoir of kinetic energy previously discussed—the dispatchable nature of traditional generation and the fundamental frequency of the electric grid (*i.e.*, 60 Hertz ("Hz")). Electric grids dominated by inverter-based generation resources face challenges to reliable operation on two power quality aspects. First, the non-controllable variability of solar and wind resources leads to voltage and frequency fluctuations that require mitigation in order to balance the instantaneous supply and demand across the electric grid. Second, inverters operate by creating harmonic frequencies, multiples of the 60 Hz fundamental, and these harmonics can cause a variety of issues including reduced system transmission capacity and premature aging of electrical equipment. These power quality issues will have to be studied and resolved over time.

7.5.4 Reactive Resources and Voltage Control

Electrical generation can be divided into real power and reactive power. Real power does actual work (*e.g.*, creating heat and light). Reactive power supports electromagnetic fields required to control voltage levels and move real power across the electric grid. Traditional voltage regulation devices that adjust reactive power are traditional rotating synchronous generators, transformer load tap changers, voltage regulators, capacitor banks, and reactor banks. The variability (due to weather patterns) and historical operation of inverter-based resources will cause added voltage variability on the system, requiring the implementation of technologies that can automatically mitigate this variability to maintain stable voltage across the system. An example of these technologies is Flexible Alternative Current Transmission System ("FACTS") devices, with the two most common devices being static volt-ampere reactive compensators, and static synchronous compensators ("STATCOMs"). Another example is the concept of using the inherent ability of inverters to help control voltage. These technologies need to be studied, developed, tested, and deployed because the cost of mitigating voltage control could become cost-prohibitive.

7.5.5 System Restoration and Black Start Capabilities

Large-scale blackouts negatively impact the public, the economy, and the power system itself. A proper black start system restoration plan can help to restore power quickly and effectively. Black start—which restores electric power stations and the electric grid without relying on external connections—is the most critical scenario for system restoration. A black start unit is a generator that can start from its own power without the support from the power grid, which is essential in the event of a major system collapse or a system-wide blackout. Black start units, and the generation included in the system restoration plan, must be available 24/7 and must have constant and predictable output when operational. These requirements provide difficulties for solar- and wind-generation resources, causing challenges to future black start restoration plans that will need to be studied and resolved. In addition, current black start restoration procedures start from the transmission system and quick start synchronous generation stations and then work towards restoring the distribution system. However, with significant DERs, system restoration procedures will need be evaluated to account for these DERs, including investigation into new DER technology like grid-forming inverters used in microgrids.

7.5.6 Grid Monitoring and Control Capabilities

Electricity demand that has historically been inelastic is becoming more variable and dynamic due to rapid growth of DERs. Greater temporal granularity is required to understand coincidence of system loading and DER production. Furthermore, DER production and performance contain inherent uncertainty that must be considered. Additionally, the dynamics of system loading itself is changing as new equipment and resources are integrated as unmeasured / unmetered resources, impacting the ability to understand and forecast these quantities. Low visibility and lack of control is a key problem for customer-level DERs such as roof-top or community solar, battery storage, electric vehicle charging infrastructure, and DSM. As DERs increase across the grid, investments in additional grid monitoring resources and equipment are vital. A robust and secure communications network is especially important to ensure bandwidth capacity and satisfy communication latency requirements for monitoring and control systems. The Company has proposed investments that will provide this level of granularity at the distribution level as part of its Grid Transformation Plan, as discussed further in Section 8.3. As these investments are deployed, and as the Company develops the integrated distribution planning process discussed further in Section 8.1, the outputs generated by integrated distribution planning will feed into and inform further analyses related to required controls at the transmission level.

Beyond monitoring, maintaining grid stability requires robust coordination between inverter controls, grid system protection and control systems, and electrical equipment loading capabilities. In-progress updates to the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547 will provide industry guidance on how inverter-based generation should provide automatic local (decentralized) voltage and frequency control and system disturbance ride through functionality. Decentralized control is not yet perfected, and the benefits of centralized control should still be weighed against potential failure modes inherent to decentralized algorithms. Extensive study and testing is needed to develop and deploy the safest and most reliable monitoring and control options possible. The Company is actively engaged in both the IEEE-1547 standards evaluation as well as research and development of inverter-based grid support functionality.

7.5.7 Energy Storage Requirements

Due to the intermittence and uncertainty of wind and solar generation, energy storage is vital. Excess energy from peak generation periods could also be collected with an energy storage system and released when load outpaces supply. However, significant study is needed to determine the requirements for efficient, reliable, cost-effective, and safe utilization of energy storage. Location, safety and environmental concerns, and end-of-life must be explored for all energy storage technologies and options. These battery storage pilot program discussed further in Section 8.5 will provide the Company with valuable insight and experience toward deployment of BESS in the future

7.5.8 High-voltage Direct Current

AC transmission cable systems are a mature technology, and the cost of HVDC technology is considerably higher than traditional AC transmission lines. This higher cost is mainly due to the converter stations at both ends of the DC connection. However, any AC cable length over six miles requires costly reactive power compensation infrastructure such as reactor banks, STATCOMs, or other FACTS devices. HVDC cables do not have this reactive power compensation requirement. Due to this, the cost per unit length of an HVDC line may be significantly less than a comparable high-voltage AC line over long distances. This potential lower cost is especially important when considering offshore generation and interregional transmission transfer capabilities to other areas of the system.

Other potential HVDC benefits include higher power transfer capability, smaller right-of-way requirements, lower power losses, dynamic real and reactive power control, fault ride-through, greater system strength tolerance, inertial emulation, frequency control, power oscillation damping, and black start capability. Since this HVDC technology is relatively new, the Company must rigorously study each of these applications along with other advanced control schemes to assure that it can deliver safe, reliable, and affordable power before implementing HVDC solutions.

7.5.9 Summary of Preliminary Results

In summary, the results and issues identified in this section are high level and preliminary in nature and the Company made several simplifying assumptions. As the parameters of the VCEA are identified and developed in greater detail, a comprehensive transmission plan will be developed that addresses these new technical challenges the transmission system will face. Nevertheless, Alternative Plans C and D will severely challenge the ability of the transmission system to meet customers' reliability expectations. For example, prolonged cold weather or multiple days of clouds and rain will greatly challenge the transmission system operators who must balance load and generation resources in real-time operations, while also maintaining compliance with NERC reliability requirements. While the Company will be able to develop a transmission expansion plan that will allow for the reliable operation of the transmission system consistent with the parameters identified in the VCEA, this expansion plan will require an investment level that exceeds current transmission level expenditures and will likely exceed the future transmission level costs initially identified in this 2020 Plan.

Chapter 8: Distribution

The Company's obligation to provide safe and reliable service carries on as the Company transitions toward a cleaner energy future. In fact, providing reliable and resilient service becomes inherently more important during this transition where availability of extensive DERs and expanding electrification are added essentials. As the distribution grid evolves to support a more dynamic energy system, the Company must continuously identify new scenarios and solutions to ensure safe and reliable service. Those solutions will likely include emerging technologies such as comprehensive distributed energy resource management systems, distribution-level STATCOMs, and customer-owned assets leveraged for grid support as non-wires alternatives. Regardless of which solutions are implemented, a robust telecommunication infrastructure that provides real-time situational awareness and supports analysis and control of grid components will be essential for an adaptable and responsive distribution system.

This chapter provides an overview of the distribution planning process, and an overview of current initiatives related to the distribution grid.

8.1 Distribution Planning

Current distribution planning methodologies and processes were designed for a distribution grid in a world of centralized large-scale generation and a one-way power flow. In the evolving paradigm where DERs and other emerging technologies are increasing on the distribution grid causing two-way power flows, the Company's distribution planning process must also evolve. Distribution grids with high penetration levels of inverter-based generation resources at the feeder level face challenges to reliable operation on two power quality aspects. First, the non-controllable variability of solar and wind resources leads to voltage fluctuations that require mitigation. Second, inverters operate by creating harmonic frequencies, multiples of the 60 Hz fundamental; these harmonics can cause a variety of challenges including reduced distribution grid capacity and premature aging of electrical equipment. These power quality issues, along with the emerging changes in the distribution grid's utilization, will have to be studied and solutions will have to be incorporated over time.

In September 2019, the Company filed a white paper that provided a detailed overview of the Company's current distribution planning process, the limitations of the current process, and the integrated distribution planning ("IDP") process that the Company planned to implement going forward (the "2019 IDP White Paper"). Appendix 8A provides the 2019 IDP White Paper.

As discussed in Section 4.0 of the 2019 IDP White Paper, true IDP will require changes to people's skills, the technologies and tools they use, and processes for performing planning activities. The Company has made progress on some of the identified enhancements:

- **Section 4.1 – People.** The Company has completed the centralization of modeling and analysis activities and continues to evaluate its organizational structure as integrated distribution planning matures.

- **Section 4.2 – Technologies.** The Company continues to evaluate options for advancing IDP. Without the granular data and situational awareness from full deployment of AMI, intelligent grid devices, and control systems proposed as part of the Grid Transformation Plan, the evolution of IDP will continue to be limited based on the technologies that the Company currently has deployed.

- **Section 4.3 – Processes and Tools.**
    - **Process Enhancement 1 – Comprehensive Feeder Level Forecasting.** The Company has developed initial net metering and utility-scale DER forecasts at the feeder level based on feeder head data where available. These forecasts will be integrated with the traditional feeder-level seasonal peak load forecast in support of long-term capacity planning on the distribution grid. With just a portion of residential customer energy usage data being collected by AMI, the Company continues to refine data analytics that approximate the peak demand of non-AMI metered residential customers based upon monthly billing data. This enhancement continues to be limited to forecasting peak demands.
    - **Process Enhancement 2 – Hosting Capacity Analysis.** The Company is on track to complete an initial hosting capacity analysis and make hosting capacity maps publicly available on the Company's website by the end of 2020. This initial analysis will be static based on the limited data inputs that are available. Improvements to the hosting capacity analysis will require additional data providing more granular visibility of the grid.
    - **Process Enhancement 3 – Multi-Hour Capacity Planning Analysis.** The Company has engaged in a research and development project with EPRI focused on modernizing distribution planning using automated processes and tools. The project is a multi-year effort with the objective of developing, testing, and demonstrating new methods and tools to automate planning assessments and support holistic decision-making in support of integrated distribution planning. Similar to the hosting capacity analysis, specific Grid Transformation Plan investments that gather highly granular grid data are necessary to support robust distribution grid analysis.
    - **Process Enhancement 5 – Non-Wires Alternatives Analysis.** The Company has started work on two battery storage pilot projects as discussed further in Section 8.5, one of which will study batteries as a non-wires alternative to reduce transformer loading. Additionally, the Company is preparing to start working on the Locks Campus Microgrid Demonstration Project that was recently approved as part of the Grid Transformation Plan. Aspects of non-wires alternative analysis are included in the EPRI research project discussed above. In the shorter term, the Company is engaged with EPRI on the development of tools to identify metrics, analytics, and practices for efficient screening of non-wires alternative projects based on economic suitability and technical feasibility. The objective of this effort is to enable more rapid determination of non-wires alternative feasibility and viability and support effective integration of DER into future resource plans. This research is a part of EPRI's 2020 research portfolio with prototype results expected by the end the year.

The Company will provide further updates on progress toward integrated distribution planning in future Plans and update filings.

8.2 Existing Distribution Facilities

The Company's existing distribution system in Virginia consists of more than 53,000 miles of overhead and underground cable, and over 400 substations operating at distribution voltage levels ranging from 4 kV to 46 kV. The distribution system utilizes a variety of devices for functions from voltage control to power flow management, and relies on multiple operating systems for various functions from customer billing to outage management.

Section III of the executive summary of the Grid Transformation Plan filed in Case No. PUR-2019-00154 (the "GT Plan Document") provided a detailed description of the Company's existing distribution system.

8.3 Grid Transformation Plan

With the passage of the GTSA, Virginia declared electric distribution grid transformation to be in the public interest, and mandated that utilities file a plan for grid transformation. The GTSA required that any such plan "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security."

The Company set forth its comprehensive plan to transform its electric distribution grid to facilitate the integration of DERs, to enhance reliability and security, and to improve the customer experience—the Grid Transformation Plan. The GT Plan Document described the need for grid modernization, the state of the existing distribution system, the development of the Grid Transformation Plan, an overview of the Grid Transformation Plan itself, and the associated customer benefits.

The Company has sought approval of the first three years of its ten-year Grid Transformation Plan (*i.e.*, 2019, 2020, and 2021) in two separate proceedings before the SCC, Case Nos. PUR-2018-00100 and PUR-2019-00154. The GT Plan Document includes information on the need, costs, and benefits of each of the proposed investments. Over these two proceedings, the SCC has approved as reasonable and prudent investments in (i) a customer information platform; (ii) a hosting capacity analysis; (iii) the Locks Campus Microgrid Project; (iv) mainfeeder hardening; (v) targeted corridor improvement; (vi) voltage island mitigation; (vii) telecommunications; (viii) physical and cyber security; and (ix) a Smart Charging Infrastructure Pilot Program to support managed charging for EVs. The SCC recently denied, without prejudice to the Company seeking approval of the Grid Transformation Plan in future petitions, investments in (i) AMI; (ii) a self-healing grid; (iii) advanced analytics; (iv) an enterprise asset management system; and (v) proactive component upgrades. Because of the preparation schedule associated with this 2020 Plan, for purposes of the NPV results, the Company has incorporated the costs and benefits as filed in Case No. PUR-2019-00154.

The passage of the VCEA has further emphasized the need for grid transformation. The VCEA requires energy efficiency programs to achieve annual targets that reach 5% by 2025, using a 2019 baseline. Full deployment of AMI across the Company's service territory enables advanced rate options, such as time-varying rates; enhances DSM programs by providing the energy usage data that will enable more targeted suggestions to customers for measures to optimize customers' energy savings; and provides the interval data to refine evaluation, measurement, and verification. AMI also enables voltage optimization, which, as can be seen in the forecast provided in Section 4.1.5, provides an effective energy efficiency program. The VCEA also envisions a significant build out of solar and wind resources. Much of this capacity would likely be connected to the distribution grid, including the 1,100 MW of small-scale solar. The situational awareness enabled by a self-healing, digital grid would prove invaluable to siting, interconnecting, and managing this significant level of renewable resources where it makes the most sense in terms of costs and benefits. Paired with the full deployment of AMI and other future investments, a self-healing, digital grid will enable more advanced and dynamic hosting capacity analysis, as well as advancements in integrated distribution planning as discussed in Section 8.1. Overall, the Grid Transformation Plan is vital to achieving the clean energy goals discussed in this 2020 Plan.

8.4 Strategic Undergrounding Program

The Company is continuing the SUP, which is in its seventh year. Originally conceived as a 4,000 mile program in 2014, the Company has converted approximately 1,325 miles of outage-prone overhead tap lines as of January 2020. A legislative sunset clause currently requires the SUP to conclude in 2028. More details on the SUP are available in the Company's annual filings with the SCC, which specify the miles of tap lines converted and their location, tap line reliability performance pre- and post-conversion, and system-wide reliability statistics.

Both local and system-wide benefits are key aspects of the SUP. Specifically, the SUP was designed to shorten restoration times in severe weather events by reducing the number of labor-intensive work locations associated with outage-prone single phase overhead tap lines, especially those in the rear of houses with significant tree coverage. By converting those tap lines to underground, directly served customers will either see a shorter outage or no outage. Perhaps more importantly, this enables crew redeployment to other outage locations, allowing a faster recovery after severe weather events for the benefit of all customers. The SUP remains the most effective and comprehensive solution for eliminating work associated with systemic tap line outages, and is complemented by the mainfeeder hardening program in the Grid Transformation Plan, which targets mainfeeders serving customers with the poorest reliability.

8.5 Battery Storage Pilot Program

The Company is beginning to study the use of battery energy storage systems on its distribution system through the pilot program established by the GTSA. The SCC recently approved the deployment of two BESS on the distribution system in Case No. PUR-2019-00124:

- Through BESS-1, the Company will deploy a 2 MW/4 MWh AC lithium-ion BESS that will study the prevention of solar back-feeding onto the transmission grid at a substation located in New Kent County; and
- Through BESS-2, the Company will deploy a 2 MW/4 MWh AC lithium-ion BESS that will study batteries as a non-wires alternative to reduce transformer loading at a substation located in Hanover County.

The SCC also approved deployment of a lithium-ion BESS at the Company's Scott Solar Facility to study solar plus storage.

These BESS provide the Company the opportunity to study important statutory objectives, and the information and experience gained from each will provide valuable insight and experience toward deployment of BESS in the future. The Company continues to explore additional unique energy storage use cases for future consideration within the battery storage pilot program.

8.6 Electric School Bus Program

The Company's Electric School Bus Program combines the Company's efforts with energy storage technologies and electric vehicles, while at the same time assisting customers' decarbonization efforts. In addition to reducing the carbon footprint of the Commonwealth and improving air quality for students, the batteries in electric school buses can be used to increase the stability and reliability of the grid, and can help to facilitate the integration of renewable energy resources such as solar and wind onto the distribution system. In Phase I of this Program, the Company intends to bring 50 electric school buses to 16 localities in the Company's service territory by the end of 2020.

This Electric School Bus Program, coupled with a modernized grid, will allow the Company to gain understanding and knowledge related to (i) the changes in system loading due to increased adoption of electric vehicle technology; (ii) the managed charging strategies necessary to accommodate a large presence of EVs on the grid; (iii) V2G technology that leverages bus batteries to store and inject energy onto the grid during periods of high demand when the buses are not needed for transport; and (iv) strategic deployment of EVs as resources for the benefit of customers and the grid.

8.7 Rural Broadband Pilot Program

The Company plans to participate in the pilot program established by House Bill 2691 from the 2019 Regular Session of the Virginia General Assembly to support the delivery of broadband service to unserved areas in Virginia. Through the broadband pilot program, the Company plans to leverage the telecommunications infrastructure deployed as part of the Grid Transformation Plan by using a portion of the fiber capacity to meet its own distribution system needs, and then leasing another portion to an internet service provider. By utilizing the telecommunication infrastructure for both operational needs and broadband access, the Company can reduce broadband deployment costs for internet service providers, which these providers would then use to deliver high-speed internet access to unserved residences and business. The Company has partnered with a subsidiary of Prince George Electric Cooperative to extend access to approximately 2,400 Company customers and 1,200 cooperative members in Surry County currently not offered broadband services. Additionally, the Company has entered into a memorandum of understanding with All Points Broadband, Northern Neck Electric Cooperative, and the Counties of King George, Northumberland, Richmond, and Westmoreland to advance a regional broadband partnership that aims to deliver fiber-optic broadband service to unserved households and businesses in Virginia's Northern Neck region.

Chapter 9: Other Information

This chapter provides other information in response to specific SCC or NCUC requirements.

9.1 Customer Education

The Company is committed to improving the customer experience. Key to achieving this goal is educating customers about their energy consumption and how to manage their costs, and empowering customers to take advantage of the numerous enhanced customer capabilities enabled by the Grid Transformation Plan and other initiatives.

The Company's customer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption and taking advantage of new incentives and offerings.

Website and Supporting Print Collateral

State: Virginia and North Carolina

The Dominion Energy website is a main hub for public education. The Company offers program- and project-specific information, factsheets, brochures, videos, and other supporting documents to provide background and updates on the benefits and enhanced capabilities associated with a variety of investments and initiatives. These include, but are not limited to, approved elements of the Grid Transformation Plan, major infrastructure projects, and new offerings (such as rates, tools and mobile apps) as they become available.
https://www.dominionenergy.com

Social Media

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 Company also manages pages on YouTube® and Instagram for further outreach to the general public, residential customers, and business customers. LinkedIn is leveraged for reaching commercial and industrial customers.
The Company's Twitter® account is available online at: https://twitter.com/dominionenergy
The Company's Facebook® account is available online at:
https://www.facebook.com/dominionenergy
The Company's YouTube® account is available online at
https://www.youtube.com/user/DomCorpComm
The Company's Instagram account is available online at
https://www.instagram.com/dominionenergy/.
The Company's LinkedIn account is available online at
https://www.linkedin.com/company/dominionenergy//

News Releases

State: Virginia and North Carolina

The Company prepares news releases and reports on the latest developments regarding its customer-facing initiatives and provides updates on Company offerings and recommendations for saving energy as new information and programs become available. Current and archived news releases can be viewed at: https://news.dominionenergy.com/news.

Customer Information Platform
State: Virginia and North Carolina
The customer information platform—recently approved by the SCC as part of the Grid Transformation Plan—will enable the Company to provide customers with better information. For example, customers will be able to utilize various notification, billing, and pay options to more easily monitor usage and to take advantage of new rate structures and rate comparison tools. Overall, with the new capabilities and customer functionality within the customer information platform, customers will be in a better position to save time and money.

Energy Conservation Programs
State: Virginia and North Carolina
The Company's website has a section dedicated to energy conservation that contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Dozens of programs are featured on the website and include eligibility guidelines, program details, steps to enroll, and success stories, as well as contact information to speak with program specialists. Through consumer education using a variety of channels to reach multiple customer classes, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina.

Online Energy Calculators
State: Virginia and North Carolina
The Company is committed to helping customers save on their energy bills and provides saving tips and a "Lower My Bill Guide" on the Company website. Home and business energy calculators are provided as well 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. For customers considering the environmental impact of transportation choices, a calculator is offered to compare emissions and cost savings of cars side-by-side with more efficient hybrid or all-electric vehicles. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at: https://www.dominionenergy.com/home-and-small-business/ways-to-save/energy-saving-calculators.

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 program information to both residential and commercial audiences. The Company also participates in various trade shows and exhibits at energy-related events to educate customers on the Company's programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses and taking advantage of new rates and offerings as they become available. Company representatives positively impact the communities the Company serves through presentations to elementary, middle, and high school students about its programs, wise energy use, and environmental stewardship. Additional partnerships with the educational community are offered through

mentoring initiatives, philanthropic support and other means to strengthen science, technology, engineering, and mathematics competitiveness in an effort help prepare students for tomorrow's workplace. Information on educational grants, scholarships, and programs for teachers and students is available on the Company's website at:
https://www.dominionenergy.com/company/community/educational-programs

For example, Project Plant It! is an educational community learning program available to students in the service areas where the Company conducts business. The program teaches students about the importance of trees and how to protect the environment through a variety of hands-on teaching tools such as a website with downloadable lesson plans for use at home and in classrooms, instructional videos, and interactive games. To enhance the learning experience, Project Plant It! provides each enrolled student with a redbud tree seedling to plant at home or at school. Since 2007, more than 500,000 tree seedlings will have been distributed to children in states where the Company operates. According to the Virginia Department of Forestry, this equates to about 1,250 acres of new forest if all the seedlings are planted and grow to maturity. Visit website for more information, https://projectplantit.com/.

9.2 Effect of Infrastructure Programs on Overall Resource Plan

The SCC directed an analysis of how the deployment and costs of infrastructure programs on the Company's transmission and distribution systems affect the Company's overall resource plan, including the Grid Transformation Plan, the Underground Transmission Line Pilot, the Battery Storage Pilot, and the Strategic Undergrounding Program. The following sections discuss each program in turn. Overall, the Grid Transformation Plan and the Battery Storage Pilot should directly affect the Company's overall resource plan in the future by facilitating the integration of DERs, and by potentially lowering demand through enhanced DSM. Deployment of these investments and further analysis is needed before the Company can quantify the reduction in costs associated with these effects on the proposed build plans.

9.2.1 Grid Transformation Plan

Many of the Grid Transformation Plan components described in Section 8.3 will have a meaningful influence on the Company's overall resource plan in the future, enabling awareness and analysis that will be critical for the Company to adapt to significant renewable capacity growth in the coming years.

As discussed in Section 8.1, the Company plans to implement an integrated distribution planning process going forward, which will provide inputs into future resource planning. Specifically, IDP will entail advanced distribution modeling and analysis capabilities that consider a range of possible futures where varying levels of DERs and emerging technologies are adopted on the distribution grid. Mature IDP is dependent on having highly granular and spatial visibility of existing grid conditions that is not available today; many of the Grid Transformation Plan components are foundational to IDP, including AMI, intelligent grid device, secure telecommunications infrastructure, and an advanced distribution management system with system capabilities for distributed energy resources management. In addition, advanced analytics are necessary to process this data, and provide the processes to suitably model the behavior of the entire distribution grid including the renewable resources. These applications can analyze weather patterns along with past generation profiles and forecast the generation that will be available from the DERs. Advanced analytics will also highlight opportunities for non-wires alternatives to be evaluated. As IDP capabilities increase, the Company can include a quantification of aggregate DER impacts to the Company's overall resource plan.

As part of the Grid Transformation Plan, the Company will make static hosting capacity maps for both utility-scale and net metering DER publicly available by the end of 2020. The situational awareness enabled by hosting capacity analysis will prove invaluable to siting, interconnecting, and managing significant levels of DER. As AMI and intelligent grid devices are deployed, and as grid visibility and operational capabilities increase, the hosting capacity analysis will become more dynamic and will support opportunities to reduce interconnection costs when DER output can be informed and adjusted through non-firm DER capacity agreements to avoid grid limitations utilizing a distributed energy resources management system.

The Grid Transformation Plan will also facilitate the integration of DERs by enhancing the reliability and resiliency of the grid, increasing the availability of the output from these DERs. Specifically, the mainfeeder hardening program will reduce sustained outages on poorly performing feeder segments, improving availability on outage prone mainfeeders to support both utility-scale and residential DERs.

Finally, the Grid Transformation Plan includes the Locks Campus Microgrid Demonstration Project. This pilot project marries several DER technologies and, similar to the Battery Storage Pilot, will provide the research and operational experience needed to prove the viability of advanced grid support capabilities, non-wires alternatives, and other functionality of DER on the Company's distribution grid.

In addition to facilitating the integration of DERs, the Grid Transformation Plan will affect the overall resource plan by potentially lowering demand through enhanced DSM. As discussed in Section 8.3, AMI enables advanced rate options, such as time-varying rates; enhances DSM programs by providing energy usage data that will enable more targeted suggestions to customers for measures to optimize energy savings; and provides the interval data needed for more refined evaluation, measurement, and verification. In addition, AMI enables voltage optimization, which can lead to significant energy savings, as discussed in Section 4.1.5. The Grid Transformation Plan also includes the Smart Charging Infrastructure Pilot Program, which will provide the information needed in furtherance of future managed charting pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid. Managing increasing EV charging load could also minimize costs for the Company and its customers, such as the need for additional distribution upgrades or the need for more fast ramping peaker plants.

9.2.2 Battery Storage Pilot Program

The Battery Storage Pilot Program discussed in Section 8.5 will provide the Company the opportunity to study important statutory objectives, and the information and operational experience gained from each project will provide valuable insight and experience toward integration of the significant energy storage capacity. Indeed, one of the pilot projects seeks to study solar plus storage, with both AC- and DC-coupled BESS, the results of which will inform the deployment of this paired application in the future.

9.2.3 Underground Line Programs

Two of the Company's infrastructure programs relate to undergrounding lines—the Strategic Undergrounding Program and the Underground Transmission Line Pilot. As discussed in Section 8.4, the Strategic Undergrounding Program converts the most outage-prone electric distribution tap lines to underground to improve customer reliability. An indirect benefit of the SUP to the overall resource plan may be to support expanded residential DER by improving availability on the formerly outage-prone tap lines. The Underground Transmission Line Pilot contemplates two underground electric transmission projects to further the Company's understanding of underground electric transmission lines. The purposes of these programs differ from the Grid Transformation Plan and the Battery Storage Pilot Program, and any potential benefits to the overall resource plan are indirect.

9.3 GTSA Mandates

Figure 9.3.1 provides a list of "mandates" from the GTSA and the accompanying citation to the GTSA. The sections that follow outline these mandates and detail the Company's plans related to each one. Several provisions of the GTSA encourage specific public policies, such as greater deployment of renewable energy, without taking the form of a mandate.

Figure 9.3.1 – GTSA Mandates

Mandate	Citation
Evaluate in future Plans: (i) electric grid transformation projects, (ii) energy efficiency measures, and (iii) combined heat and power or waste heat to power	Va. Code § 56-599; EC 12; EC 18
Adjust rates to reflect the reduction in corporate income taxes	EC 6; EC 7
Provide one-time, voluntary bill credits	EC 4; EC 5
Offer Manufacturing and Commercial Competitiveness Retention Credit	EC 11
File triennial review	Va. Code § 56-585.1; Va. Code § 56-585.1:1
Report on potential improvements to renewable programs	EC 17
Report on economic development activities	EC 16
Report on the feasibility of providing broadband using utility infrastructure	EC 13
Report on energy efficiency programs by an independent monitor	EC 15 Va. Code § 56-596.2
Fund energy assistance and weatherization pilot program	Va. Code § 56-585.1:2
Propose a plan to deploy 30 MW of battery storage under new pilot program	Va. Code § 56-585.1:6 (EC 9; EC 10)
Propose a plan for electric distribution grid transformation projects	Va. Code § 56-585.1 A 6
Propose a plan for energy conservation measures with a projected cost of no less than $870 million	Va. Code § 56-596.2 (EC 15)

Note: "EC" = Enactment Clause

9.3.1 Plan-Related Mandates

This 2020 Plan includes all of the analyses required by Va. Code § 56-599, including long-term planning related to the distribution grid and energy efficiency measures. In this Plan, the Company considered combined heat and power as a possible generation resource as required by Enactment Clause 12 of the GTSA, as discussed in Section 5.5. Finally, Section 6.6 provides the analysis related to energy efficiency measures required by Enactment Clause 18 of the GTSA.

9.3.2 Rate-Related Mandates

The GTSA contained a number of mandates related to customer rates. The Company has complied or will comply with each of these provisions:

- The Company reduced its rates for generation and distribution services by $182.574 million to reflect the reduction in corporate income taxes under the federal Tax Cuts and Jobs Act of 2017 consistent with Enactment Clauses 6 and 7 of the GTSA. See SCC Case No. PUR-2018-00055.

- The Company issued one-time, voluntary generation and distribution services bill credits totaling $200 million consistent with Enactment Clauses 4 and 5 of the GTSA. See SCC Case No. PUR-2018-00053.

- The Company began offering a Manufacturing and Commercial Competitiveness Retention Credit, designated Rider CRC, to eligible customers consistent with Enactment Clause 11 of the GTSA. See SCC Case No. PUR-2018-00133.

- The Company will make a triennial review filing by March 31, 2021.

9.3.3 Mandated Reports

The GTSA mandated a list of reports for the Company to file with the SCC and others. The Company has filed the following reports:

- Solar Energy Report (Nov. 1, 2018) (EC 17);
- Economic Development Report (Dec. 1, 2018) (EC 16);
- Broadband Feasibility Report (Dec. 1, 2018) (EC 13); and
- The Report of the Independent Monitor on the Status of the Energy Efficiency Stakeholder Process (Jun. 28, 2019) (EC 15, Va. Code § 56-596.2).

9.3.4 Pilot Program Mandates

The GTSA contained two mandates related to pilot programs. First, under the amended language in Va. Code § 56-585.1:2, the Company must continue its pilot program for energy assistance and weatherization for low income, elderly, and disabled individuals "at no less than $13 million for each year the utility is providing such service." The Company has continued this pilot program and has met the required funding.

Second, the GTSA required the SCC to establish a pilot program for storage batteries. The SCC established guidelines for this pilot program on November 2, 2018, in Case No. PUR-2018-00060. The SCC approved the Company's first application to participate in the pilot program on February 14, 2020, allowing for the deployment of three BESS projects totaling 16 MW.

9.3.5 Mandate Related to Electric Distribution Grid Transformation Projects

The GTSA mandated that the Company petition the SCC for approval of a plan for electric distribution grid transformation projects. Section 8.3 provides details on the Company's Grid Transformation Plan.

9.3.6 Mandate Related to Energy Conservation Measures

The GTSA directed the Company to develop a proposed program of energy conservation measures with a proposed cost of no less than $870 million by July 1, 2028, and established an energy efficiency stakeholder process. See Chapter 6 for more details on the Company's DSM initiatives.

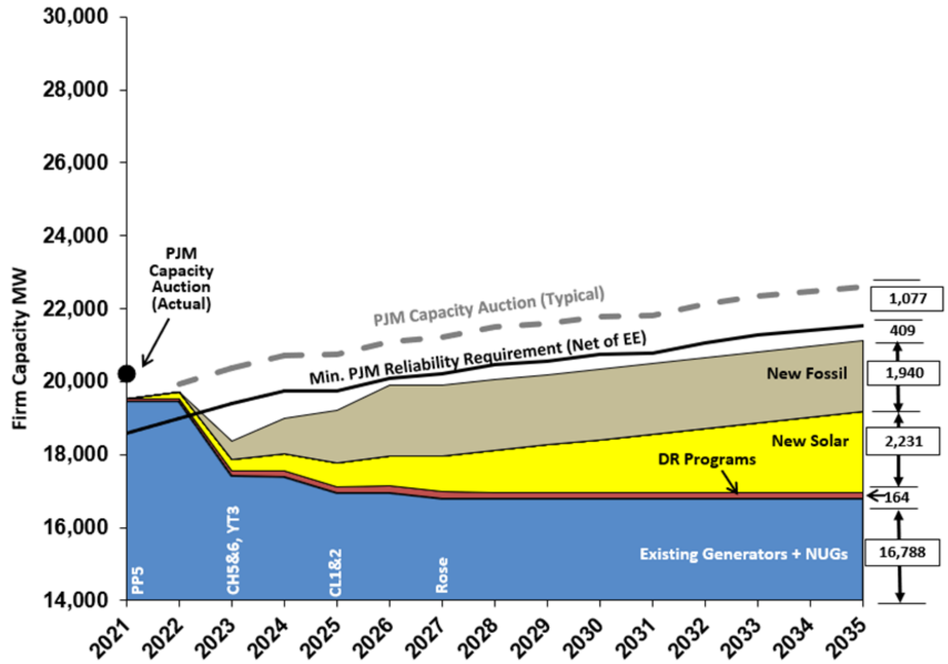
9.4 Economic Development Rates

As of March 1, 2020, the Company has seven unique customers located in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 154 MW. As of March 1, 2020, the Company has no customers in North Carolina receiving service under economic development rates.

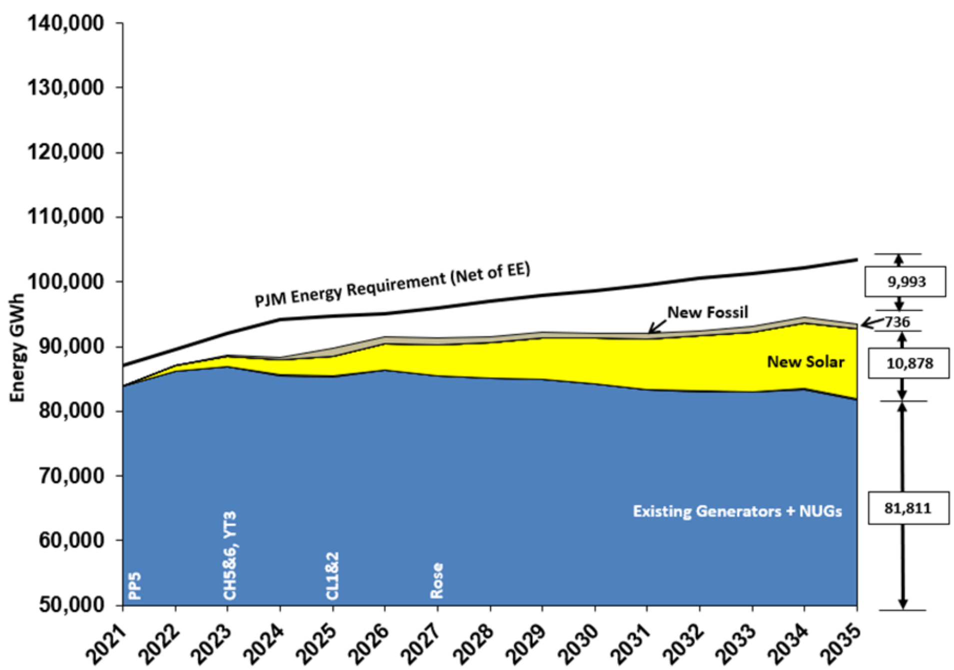
APPENDIX

Appendix 2A – Plan A – Capacity & Energy

Capacity



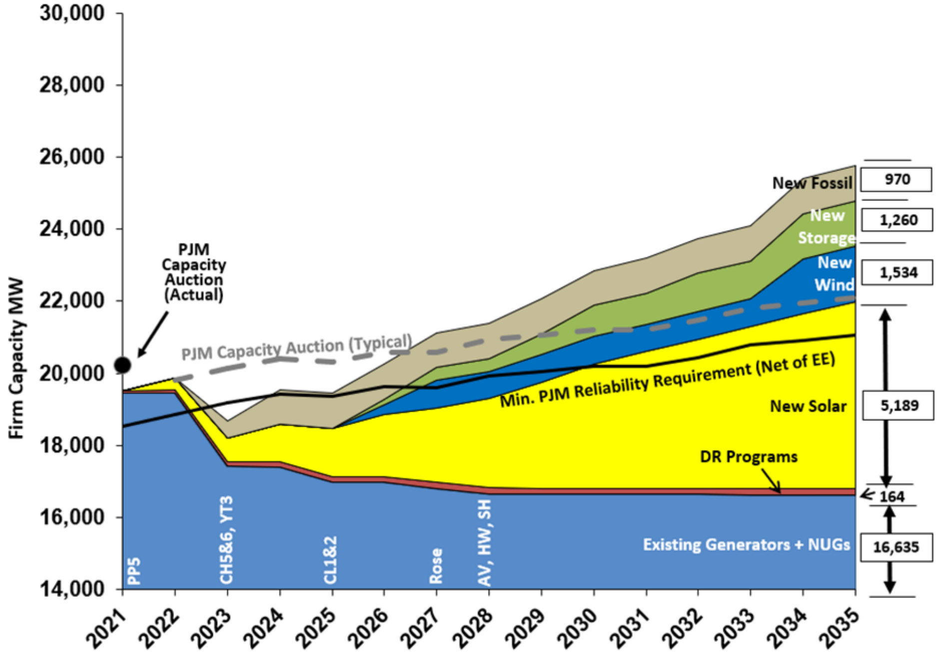
Energy



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil).

Appendix 2A cont. – Plan B – Capacity & Energy

Capacity



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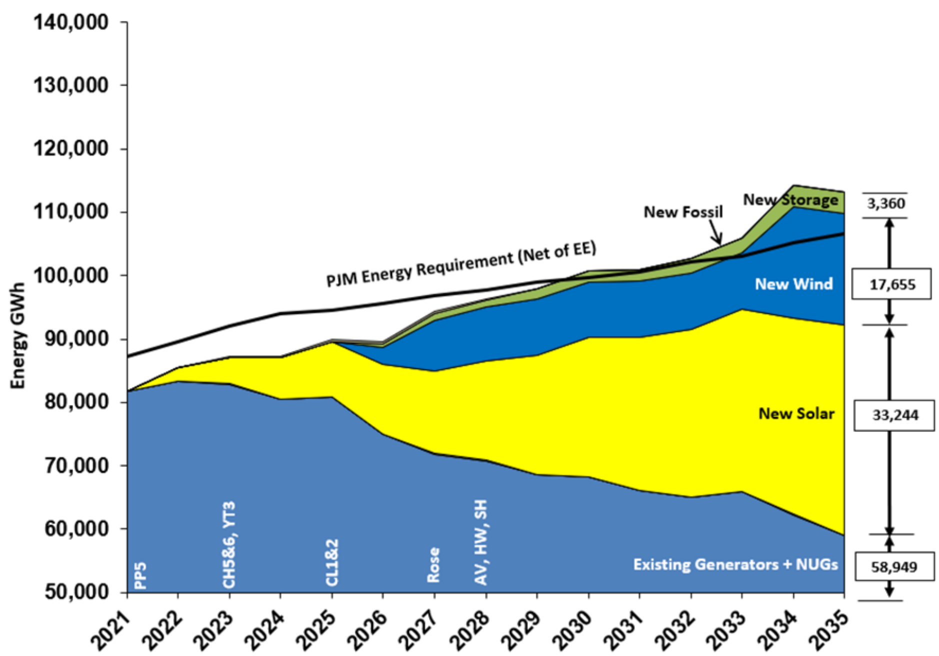
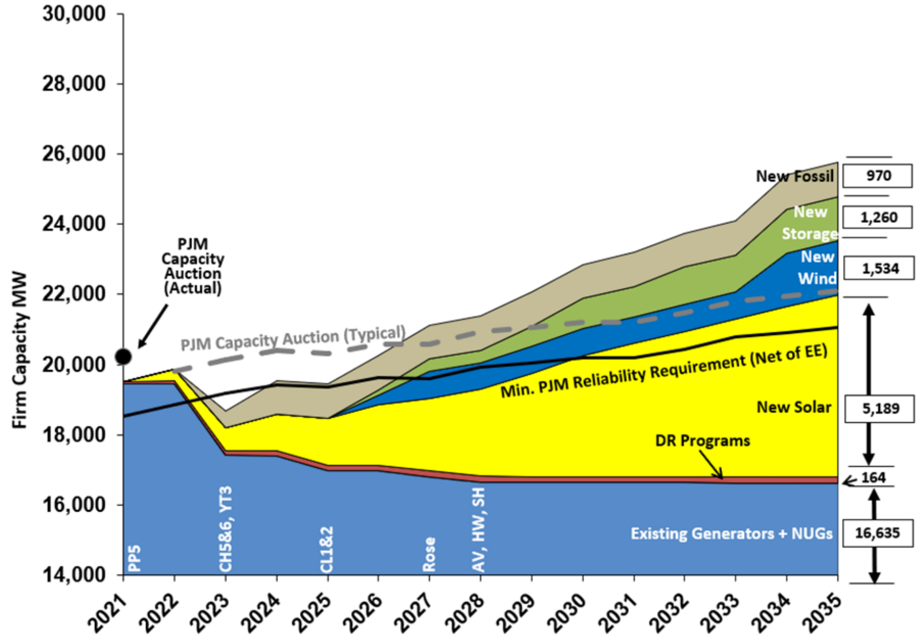


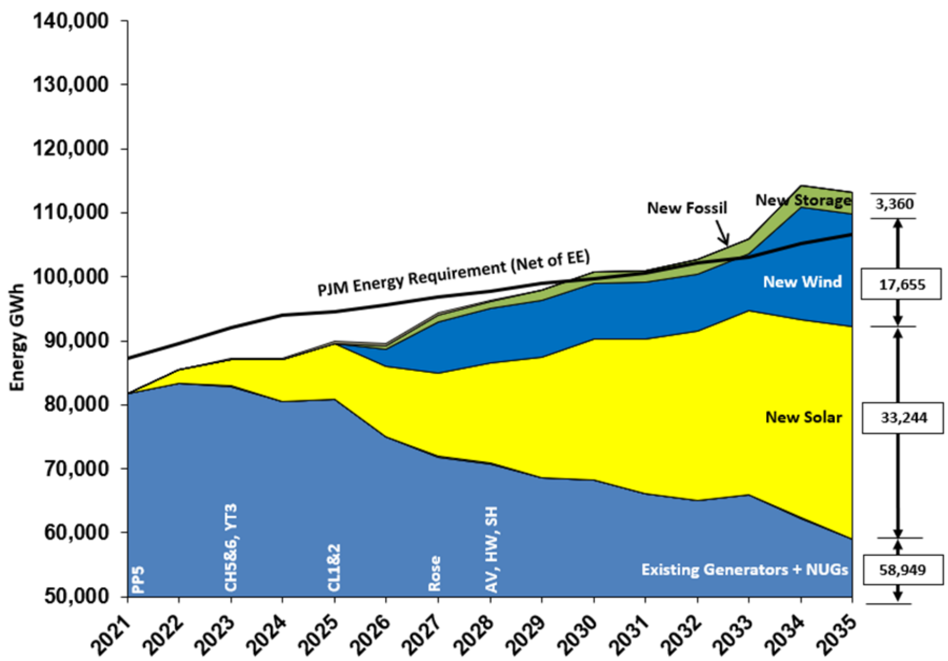
Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Appendix 2A cont. – Plan C – Capacity & Energy

Capacity



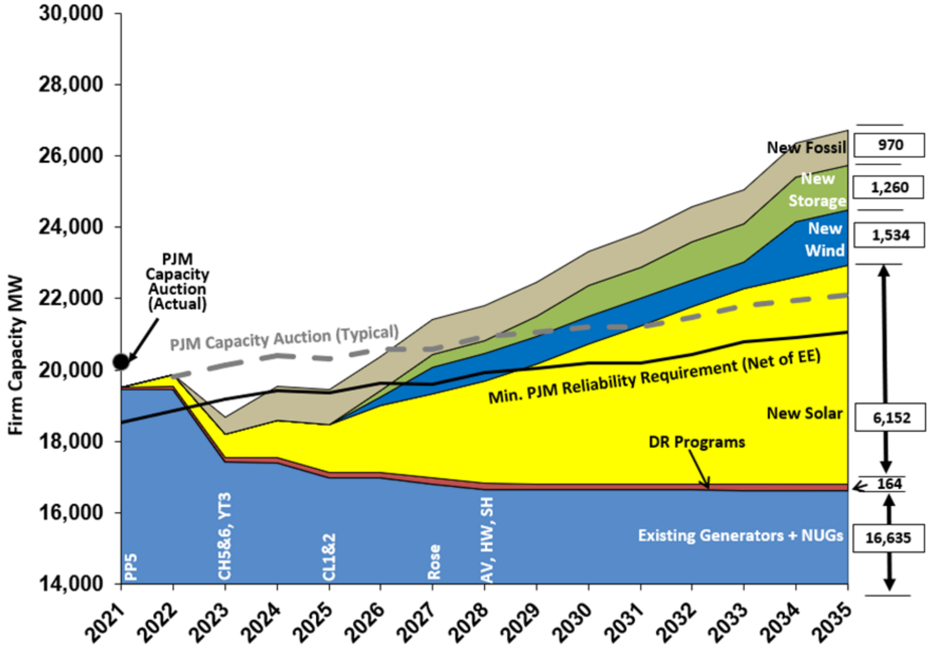
Energy



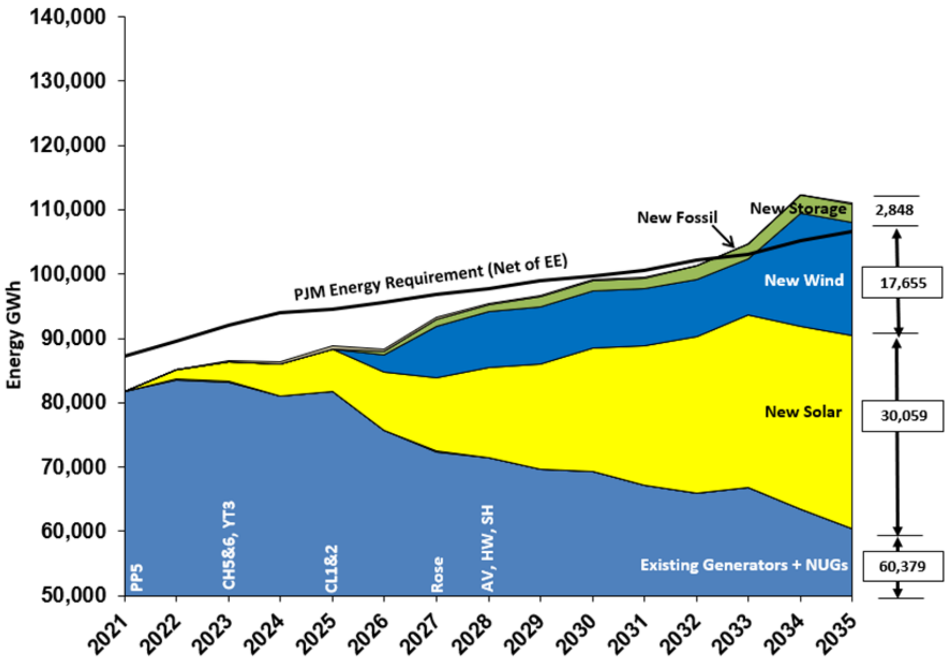
Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Appendix 2A cont. – Plan D – Capacity & Energy

Capacity



Energy



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Appendix 3A – 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 Annual Firm	MW Nameplate
Under Construction						
Spring Grove 1 Solar	VA	Intermittent	Solar	2021	34	98
Sadler Solar	VA	Intermittent	Solar	2021	34	100
CVOW Demonstration Pilot	VA	Intermittent	Wind	2021	4	12$^{(2)}$
Solar + Storage Battery Pilot	VA	Storage	Solar	2021	5	12

Notes: 1) Commercial Operation Date.
2) Accounts for line losses.

Appendix 3B – 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.[2]	MW Summer	MW Nameplate
Under Development[1]						
Surry Unit 1 Nuclear Extension	VA	Baseload	Nuclear	2032	838	875
Surry Unit 2 Nuclear Extension	VA	Baseload	Nuclear	2033	838	875
North Anna Unit 1 Nuclear Extension	VA	Baseload	Nuclear	2038	838	868
North Anna Unit 2 Nuclear Extension	VA	Baseload	Nuclear	2040	834	863
Solar 1	VA	Intermittent	Solar	2022		42
Solar 2	VA	Intermittent	Solar	2022		118
Solar 3	VA	Intermittent	Solar	2022		85
Solar 4	VA	Intermittent	Solar	2022		20
Combustion Turbine 1	VA	Peaker	Natural Gas	2023	485	485
Combustion Turbine 2	VA	Peaker	Natural Gas	2024	485	485
Offshore Wind Block 1	VA	Intermittent	Wind	2026		852
Offshore Wind Block 2	VA	Intermittent	Wind	2027		852
Offshore Wind Block 3	VA	Intermittent	Wind	2027		852
Tazewell Pump Storage	VA	Storage	Water	2030	300	300

Notes: 1) Includes the additional resources under development in the Alternative Plans.
2) Estimated commercial operation date.

Appendix 3C – Comparison of Short-Term Action Plans for Generation Resources in 2018 Plan and 2020 Plan

Supply-Side Resources				
Year	**New Conventional**	**New Renewable**	**Retire**	**Demand-side Resources**
2021		US-3 Solar 2 CVOW **SLR (600 MW)**	PP 5	**Approved DSM** ↓
2022	~~CT~~	**SLR (480 MW)**	~~YT 3~~	
2023	CT	**BESS (14 MW)** **SLR (480 MW)**	**YT 3, CH 5-6**	
2024	**CT**	**SLR (780 MW)**		
2025		**SLR (480 MW)**	**CL 1-2**	

Key: Retire: Remove a unit from service; BESS: Battery Energy Storage Systems; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine; CVOW: Coastal Virginia Offshore Wind Demonstration Pilot; PP: Possum Point Power Station; SLR: Generic Solar; US-3 Solar 2: Spring Grove 1 Solar Facility; YT: Yorktown Power Station.

Color Key: Blue: Updated resource since 2018 Plan; Red with Strike: 2018 Plan resource replacement; Black: No change from 2018 Plan.

Appendix 3D - List of Planned Transmission Projects During the Planning Period

Line Terminals	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Sandlot 230 kV Delivery - DEV	230	Mar-20	VA	5.5
Freedom Substation (Redundant 69 kV Facility)	69	Mar-20	VA	5.4
Fork Union Sub to mitigate Bremo Units 3 & 4 Reserve Status	115; 230	Apr-20	VA	27.0
Line #548 Valley Switching Station Fixed Series Capacitors replacement	500	Apr-20	VA	16.8
Line #547 Lexington Substation Fixed Series Capacitors Replacement	500	Apr-20	VA	17.7
Gordonsville Transformer #3 Replacement	230/115	May-20	VA	3.5
Skippers - New 115 kV Switching Station	115	May-20	VA	8.0
Genito 230 kV Delivery Point - DEV	230	May-20	VA	10.0
Spring Hill 230 kV Delivery	230	May-20	VA	35.0
Idylwood - Convert Straight Bus to Breaker-and-a-Half	230	May-20	VA	103.1
Line #217 Chesterfield to Lakeside Rebuild	230	May-20	VA	41.5
Line #211 and #228 Chesterfield to Hopewell Partial Rebuild	230	May-20	VA	28.5
Line #2199 Remington to Gordonsville – New 230 kV Line	230	May-20	VA	112.0
Line #86 Partial Rebuild Project	115	May-20	VA	7.0
Greenwich Substation – New line #120 Breaker	115	May-20	VA	1.5
Line #549 Dooms to Valley Rebuild	500	Jun-20	VA	62.3
Paragon Park 230 kV Delivery - DEV	230	Jul-20	VA	2.5
Winterpock 230 kV Delivery and 230 kV Ring Bus	230	Sep-20	VA	8.5
Line #76 and #79 Yorktown to Peninsula Rebuild	115	Oct-20	VA	24.5
Columbia Tap - CVEC	115	Oct-20	VA	7.0
Dawson's Crossroads – Delivery Point (HEMC)	115	Nov-20	NC	0.7
Global Plaza 230 kV Delivery - DEV	230	Nov-20	VA	40.0
Winters Branch 230 kV New Substation	230	Dec-20	VA	7.1
Line #112 Fudge Hollow to Lowmoor Rebuild	138	Dec-20	VA	12.6
Perimeter 230 kV DP - NOVEC	230	Dec-20	VA	8.0
Line #231 Landstown to Thrasher Rebuild	230	Dec-20	VA	19.0
Buttermilk 230 kV Delivery - DEV	230	Dec-20	VA	11.0
Line #154 Twittys Creek to Pamplin Rebuild	115	Dec-20	VA	18.1
Line #101[1] Mackeys to Creswell Rebuild	115	Dec-20	NC	36.7
Poland Road 230 kV Delivery - Add 4th Transformer - DEV	230	Dec-20	VA	2.0
Clarksville Tap Line 193 Rebuild	115	Dec-20	VA	3.2
Peninsula Transformer #4 Replacement and 230 kV Ring Bus	230	Apr-21	VA	16.1
Clover Substation – New 500 kV STATCOM and Rawlings Switching Station – New 500 kV STATCOM	500	May-21	VA	47.0
Farmwell 230 kV Delivery	230	May-21	VA	6.2
Evergreen Mills 230 kV Delivery	230	May-21	VA	27.8
Ladysmith 2nd 500-230 kV Transformer	230	May-21	VA	25.0
Line #274 Pleasant View to Beaumeade Rebuild	230	Jun-21	VA	10.0
Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230 kV Lines and New 230 kV Substation	230	Jul-21	VA	176.0
Lucky Hill Substation	115; 230	Jul-21	VA	7.5
Varina Substation	230	Nov-21	VA	0.9
DTC 230 kV Delivery - DEV	230	Nov-21	VA	25.0
Line #49 New Road to Middleburg Rebuild	115	Dec-21	VA	12.7
Line #65 Norris Bridge Rebuild	115	Dec-21	VA	103.0
Line #550 Mount Storm to Valley Rebuild	500	Dec-21	WV– VA	288.2
Line #120 Dozier to Thompsons Corner Partial Rebuild	115	Dec-21	VA	12.6

Appendix 3D cont. - List of Planned Transmission Projects During the Planning Period

Line Terminals	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line #127 Buggs Island to Plywood Rebuild	115	Dec-21	VA	42.4
Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Rebuild	115	Dec-21	VA	27.0
New Switching Station to Retire Line #139[2] Everetts to Windsor DP;Line #139 Everetts to Windsor DP Retirement	115	Dec-21	NC	11.5
Line #2008 Partial Rebuild and Line #156 Retirement	115;230	Dec-21	VA	14.5
Line #128 Rebuild Mt. Jackson -SVEC	115	Dec-21	VA	13.1
Line #2023 and Line #248 Potomac Yards Undergrounding & Glebe GIS Conversion	230	May-22	VA	120.0
Mt. Storm - GIS	500	May-22	WV	69.0
Line #2001 Possum Point to Occoquan Reconductor and Uprate	230	Jun-22	VA	4.7
Line #43 Staunton - Harrisonburg Rebuild	115	Jun-22	VA	39.6
Lockridge 230 kV Delivery - DEV	230	Jul-22	VA	35.0
Nimbus 230 kV Delivery - DEV	230	Nov-22	VA	20.0
Line #2175 Idylwood to Tyson's – New 230 kV Line	230	Dec-22	VA	121.8
Line #552 Bristers to Chancellor Rebuild	500	Dec-22	VA	62.2
Line #247[3] Suffolk to Swamp Rebuild	230	Dec-22	VA-NC	31.0
Line #205 and #2003 Chesterfield to Tyler Partial Rebuild	230	Dec-22	VA	11.1
Line #29 Fredericksburg to Possum Point Partial Rebuild	115	Dec-22	VA	19.2
Line #295 and Partial Line #265 Rebuild	230	Dec-22	VA	15.5
Line #2173 - Loudoun to Elklick Rebuild	230	Dec-22	VA	13.5
Line #2144[4] Winfall to Swamp Rebuild	230	Dec-22	NC	6.0
Judes Ferry 230 kV DP	230	May-23	VA	1.1
Fines Corner 230 kV DP	230	May-23	VA	1.0
Brickyard 230kV Delivery	230	May-23	VA	2.0
Possum Point 2nd 500-230 kV Transformer	500/230	Jun-23	VA	21.0
Line #227 Partial Rebuild	230	Jun-23	VA	15.8
Possum Point Breakers Replacement	230	Jun-23	VA	19.0
Prince Edward 230 kV DP	230	Nov-23	VA	1.2
Line #581 Chancellor - Ladysmith 500 kV Rebuild	500	Dec-23	VA	44.4
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild and Fort Eustis Tap Rebuild	115	Dec-23	VA	24.2
Line #224 Lanexa to Northern Neck Rebuild	230	Dec-23	VA	86.0
Lines #265, 200, and 2051 Partial Rebuild	230	Dec-23	VA	11.5
Line #141 & Line #28 Rebuild	115	Dec-23	VA	20.0
Line #574 Elmont to Ladysmith Rebuild	500	Dec-24	VA	65.5
Line #2113 Waller to Lightfoot Partial Rebuild	230	Dec-24	VA	4.0
Line #2154 and #19 Waller to Skiffes Creek Rebuild	230	Dec-24	VA	10.0
Lines #2063 and Partial #2164 Rebuild	230	Dec-24	VA	22.0
Line #81[5] and Partial Line #2056[6] Rebuild	115; 230	Dec-24	NC	25.0
Line #254 Clubhouse-Lakeview Rebuild	230	Dec-24	VA	27.0
Line #2181[7] and Line #2058[7] Hathaway to Rocky Mount (DEP) Rebuild	230	Dec-24	NC	13.0
Line #569 Loudoun - Morrisville Rebuild	500	Dec-24	VA	4.5

Notes: 1) Line #101 capacity will be 262 MVA.
2) Line #139 capacity was 33 MVA.
3) Line #247 capacity will be 1,047 MVA.
4) Line #2144 capacity will be 1,047.
5) Line #81 capacity will be 262 MVA.
6) Line #2056 capacity will remain at 470 MVA.
7) Line #2181 and Line #2058 both capacities will be 1,047 MVA.

Appendix 4A – Total Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
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	30,184	29,372	8,097	10,261	276	1,961	80,150
2014	31,290	29,964	8,812	10,402	261	1,850	82,579
2015	30,923	30,282	8,765	10,159	275	1,620	82,024
2016	28,213	31,366	8,715	10,161	253	1,599	80,307
2017	29,737	32,292	8,638	10,555	258	1,515	82,994
2018	32,139	33,591	8,324	10,761	260	1,633	86,707
2019	31,439	35,296	7,302	10,645	263	1,580	86,524
2020	31,636	31,512	9,155	11,074	260	1,521	85,159
2021	31,790	33,177	8,978	11,190	258	1,530	86,923
2022	32,104	35,346	8,858	11,252	256	1,545	89,360
2023	32,467	37,733	8,750	11,381	254	1,562	92,147
2024	32,964	39,350	8,723	11,480	252	1,584	94,353
2025	32,384	41,842	8,510	11,451	250	1,597	96,034
2026	32,459	43,287	8,492	11,526	248	1,615	97,628
2027	32,674	45,057	8,522	11,558	246	1,632	99,689
2028	32,950	46,814	8,557	11,621	244	1,653	101,839
2029	32,859	47,833	8,476	11,697	242	1,664	102,770
2030	32,926	49,050	8,450	11,744	241	1,678	104,089
2031	32,981	50,198	8,442	11,627	239	1,694	105,182
2032	33,134	51,510	8,448	11,818	238	1,712	106,860
2033	33,090	52,463	8,452	11,705	236	1,721	107,667
2034	33,302	53,370	8,407	11,800	234	1,734	108,848
2035	33,478	54,223	8,385	11,712	233	1,747	109,778

Note: Based on the Company's internal forecast; information not provided by PJM Load Forecast.

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4B – Virginia Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	28,325	27,646	7,147	10,312	268	1,860	75,558
2010	30,831	28,408	6,872	10,529	273	1,928	78,842
2011	29,153	28,163	6,342	10,423	265	1,962	76,309
2012	27,672	28,063	6,235	10,370	269	1,897	74,507
2013	28,618	28,487	6,393	10,134	267	1,911	75,809
2014	29,645	29,130	6,954	10,272	253	1,798	78,052
2015	29,293	29,432	7,006	10,029	266	1,567	77,593
2016	26,652	30,537	6,947	10,033	245	1,547	75,961
2017	28,194	31,471	6,893	10,429	250	1,466	78,704
2018	30,437	32,752	6,598	10,633	252	1,581	82,254
2019	29,829	34,472	5,591	10,517	254	1,530	82,194
2020	30,016	30,651	7,011	10,952	251	1,473	80,355
2021	30,162	32,287	6,875	11,067	250	1,481	82,122
2022	30,460	34,425	6,783	11,128	248	1,495	84,539
2023	30,805	36,779	6,700	11,256	246	1,512	87,298
2024	31,276	38,360	6,680	11,354	244	1,533	89,447
2025	30,726	40,793	6,516	11,326	242	1,546	91,149
2026	30,797	42,205	6,503	11,400	240	1,563	92,708
2027	31,001	43,933	6,526	11,432	238	1,580	94,710
2028	31,263	45,650	6,553	11,494	236	1,600	96,795
2029	31,176	46,644	6,490	11,569	234	1,610	97,725
2030	31,240	47,834	6,471	11,615	233	1,624	99,017
2031	31,293	48,954	6,465	11,499	231	1,640	100,082
2032	31,438	50,236	6,469	11,689	230	1,657	101,719
2033	31,396	51,167	6,472	11,576	228	1,666	102,505
2034	31,597	52,053	6,438	11,671	227	1,679	103,664
2035	31,764	52,885	6,421	11,584	225	1,691	104,570

Note: Based on the Company's internal forecast; information not provided by PJM Load Forecast.

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4C – North Carolina Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
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	1,567	885	1,704	127	8	50	4,341
2014	1,645	834	1,858	130	8	53	4,527
2015	1,630	850	1,759	130	8	53	4,431
2016	1,562	829	1,768	128	8	52	4,346
2017	1,542	821	1,744	126	8	49	4,290
2018	1,701	839	1,725	128	8	52	4,453
2019	1,610	824	1,710	127	9	50	4,331
2020	1,620	861	2,144	122	9	49	4,805
2021	1,628	890	2,103	123	9	49	4,801
2022	1,644	922	2,075	123	9	49	4,822
2023	1,663	954	2,049	125	9	50	4,849
2024	1,688	990	2,043	125	8	51	4,906
2025	1,658	1,048	1,993	125	8	51	4,885
2026	1,662	1,082	1,989	126	8	52	4,919
2027	1,673	1,123	1,996	126	8	52	4,980
2028	1,687	1,164	2,004	127	8	53	5,044
2029	1,683	1,188	1,985	128	8	53	5,046
2030	1,686	1,217	1,979	129	8	54	5,073
2031	1,689	1,243	1,977	127	8	54	5,099
2032	1,697	1,274	1,979	130	8	55	5,142
2033	1,694	1,296	1,980	128	8	55	5,162
2034	1,705	1,318	1,969	129	8	55	5,185
2035	1,714	1,337	1,964	128	8	56	5,208

Note: Based on the Company's internal forecast; information not provided by PJM Load Forecast.

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4D – Total Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
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	2,206,657	236,596	526	28,847	3,508	3	2,476,138
2014	2,229,639	237,757	631	28,818	3,653	3	2,500,500
2015	2,252,438	239,623	662	28,923	3,814	3	2,525,463
2016	2,275,551	240,804	654	29,069	3,941	3	2,550,022
2017	2,298,894	242,091	648	28,897	4,149	3	2,574,683
2018	2,323,662	243,701	644	28,716	4,398	3	2,601,124
2019	2,362,949	246,043	634	28,452	4,792	3	2,642,873
2020	2,373,004	236,493	632	28,511	4,880	3	2,643,523
2021	2,397,785	238,577	631	28,622	5,024	3	2,670,642
2022	2,426,050	240,878	630	28,724	5,168	3	2,701,454
2023	2,456,258	243,310	629	28,828	5,312	3	2,734,341
2024	2,485,951	245,712	628	28,921	5,456	3	2,766,671
2025	2,515,062	248,076	627	29,003	5,600	3	2,798,371
2026	2,543,549	250,402	626	29,077	5,744	3	2,829,401
2027	2,571,023	252,665	625	29,142	5,888	3	2,859,346
2028	2,596,911	254,830	624	29,200	6,032	3	2,887,600
2029	2,621,217	256,893	623	29,248	6,176	3	2,914,161
2030	2,644,614	258,898	622	29,289	6,320	3	2,939,747
2031	2,667,401	260,865	621	29,325	6,464	3	2,964,679
2032	2,689,708	262,801	620	29,356	6,608	3	2,989,095
2033	2,711,563	264,708	619	29,383	6,752	3	3,013,029
2034	2,733,000	266,590	618	29,407	6,896	3	3,036,514
2035	2,754,158	268,453	617	29,427	7,040	3	3,059,698

Note: Based on the Company's internal forecast; information not provided by PJM Load Forecast.

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4E – Virginia Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
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	2,105,500	221,039	477	26,996	3,118	2	2,357,131
2014	2,128,313	222,143	579	26,966	3,267	2	2,381,269
2015	2,150,818	223,946	611	27,070	3,430	2	2,405,877
2016	2,173,472	225,029	603	27,223	3,560	2	2,429,889
2017	2,196,466	226,270	596	27,041	3,768	2	2,454,143
2018	2,220,797	227,757	594	26,872	4,017	2	2,480,039
2019	2,257,900	229,988	584	26,614	4,417	2	2,519,505
2020	2,267,955	219,287	583	26,680	4,457	2	2,518,964
2021	2,291,639	221,226	582	26,784	4,589	2	2,544,821
2022	2,318,653	223,367	581	26,880	4,720	2	2,574,203
2023	2,347,523	225,630	581	26,977	4,852	2	2,605,564
2024	2,375,902	227,864	580	27,064	4,983	2	2,636,395
2025	2,403,724	230,064	579	27,141	5,115	2	2,666,623
2026	2,430,950	232,227	578	27,210	5,246	2	2,696,214
2027	2,457,208	234,333	577	27,271	5,378	2	2,724,768
2028	2,481,950	236,347	576	27,325	5,509	2	2,751,709
2029	2,505,180	238,267	575	27,370	5,641	2	2,777,035
2030	2,527,541	240,132	574	27,408	5,772	2	2,801,430
2031	2,549,319	241,962	573	27,442	5,904	2	2,825,202
2032	2,570,638	243,763	572	27,471	6,036	2	2,848,482
2033	2,591,526	245,538	571	27,496	6,167	2	2,871,301
2034	2,612,014	247,288	570	27,519	6,299	2	2,893,692
2035	2,632,235	249,021	569	27,538	6,430	2	2,915,796

Note: Based on the Company's internal forecast; information not provided by PJM Load Forecast.

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4F– North Carolina Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
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	101,158	15,557	50	1,851	390	1	119,007
2014	101,326	15,614	52	1,853	386	1	119,231
2015	101,620	15,677	52	1,853	384	1	119,586
2016	102,079	15,775	51	1,846	381	1	120,133
2017	102,429	15,821	52	1,857	381	1	120,541
2018	102,865	15,944	50	1,844	381	1	121,085
2019	105,049	16,055	50	1,838	375	1	123,368
2020	105,049	17,206	49	1,831	423	1	124,559
2021	106,146	17,351	49	1,838	435	1	125,820
2022	107,398	17,511	49	1,845	448	1	127,251
2023	108,735	17,680	49	1,851	460	1	128,776
2024	110,049	17,848	49	1,857	473	1	130,277
2025	111,338	18,012	49	1,862	485	1	131,748
2026	112,599	18,174	49	1,867	498	1	133,188
2027	113,815	18,332	49	1,871	510	1	134,578
2028	114,961	18,483	48	1,875	523	1	135,891
2029	116,037	18,626	48	1,878	535	1	137,126
2030	117,073	18,766	48	1,881	548	1	138,317
2031	118,082	18,903	48	1,883	560	1	139,477
2032	119,069	19,038	48	1,885	572	1	140,614
2033	120,037	19,171	48	1,887	585	1	141,728
2034	120,986	19,302	48	1,888	597	1	142,822
2035	121,922	19,431	48	1,890	610	1	143,902

Note: Based on the Company's internal forecast; information not provided by PJM Load Forecast.

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4G – Zonal Summer and Winter Peak Demand (MW) Company Load Forecast

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2009	18,137	18,079
2010	19,140	17,689
2011	20,061	17,532
2012	19,249	16,881
2013	18,763	17,623
2014	18,692	19,784
2015	18,980	21,651
2016	19,538	18,948
2017	18,902	19,661
2018	19,244	21,232
2019	19,607	19,930
2020	20,258	18,908
2021	20,448	19,196
2022	20,709	19,656
2023	21,037	20,129
2024	21,433	20,575
2025	21,738	21,044
2026	22,048	21,609
2027	22,361	21,942
2028	22,678	22,440
2029	22,914	22,745
2030	23,109	23,169
2031	23,300	23,605
2032	23,479	23,868
2033	23,669	24,016
2034	23,869	24,295
2035	24,128	24,702

Historic (2009 – 2019). Projected (2020 – 2035).

Appendix 4H - Projected Summer & Winter Peak Load & Energy Forecast for Plan B

Company Name: Virginia Electric and Power Company **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]			(PROJECTED)																		
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,350	16,528	16,599	16,533	16,802	17,105	17,399	17,644	17,807	18,004	18,170	18,323	18,456	18,601	18,759	18,977	19,121	19,251	19,357
1b. Additional Forecast																			
NCEMC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency(5)	-109	-119	-135	-144	-190	-259	-345	-431	-513	-572	-676	-634	-613	-637	-648	-697	-599	-579	-565
3. Demand Response(2)(5)	-70	-58	-55	-63	-63	-64	-64	-65	-65	-65	-65	-66	-66	-66	-66	-66	-66	-66	-66
4. Demand Response-Existing(2)(3)	-1	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
5. Peak Adjustment	-	-	-																
6. Adjusted Load	16,241	16,409	16,464	16,389	16,612	16,846	17,053	17,213	17,294	17,432	17,493	17,689	17,843	17,964	18,112	18,279	18,523	18,672	18,792
7. % Increase in Adjusted Load (from previous year)	-3.4%	1.0%	0.3%	-0.5%	1.4%	1.4%	1.2%	0.9%	0.5%	0.8%	0.4%	1.1%	0.9%	0.7%	0.8%	0.9%	1.3%	0.8%	0.6%
B. Winter																			
1a. Base Forecast	16,618	17,792	16,842	16,737	17,004	17,356	17,711	18,074	18,448	18,621	18,807	19,008	19,168	19,371	19,537	19,676	19,839	19,974	20,120
1b. Additional Forecast																			
NCEMC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency(5)	-109	-119	-135	-240	-340	-216	-292	-404	-512	-589	-739	-579	-575	-791	-670	-693	-598	-589	-582
3. Demand Response(2)(4)	-5	-6	-6	-16	-37	-58	-76	-92	-100	-102	-103	-104	-105	-106	-107	-108	-109	-110	-111
4. Demand Response-Existing(2)(3)	-1	-1	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
5. Adjusted Load	16,509	17,673	16,707	16,497	16,664	17,140	17,419	17,670	17,936	18,032	18,068	18,429	18,593	18,580	18,867	18,983	19,241	19,385	19,538
6. % Increase in Adjusted Load	2.7%	7.1%	-5.5%	-1.3%	1.0%	2.9%	1.6%	1.4%	1.5%	0.5%	0.2%	2.0%	0.9%	-0.1%	1.5%	0.6%	1.4%	0.8%	0.8%
2. Energy (GWh)																			
A. Base Forecast	84,046	88,377	87,078	88,786	90,435	92,700	94,893	97,428	98,378	99,347	100,353	101,679	102,426	103,269	104,160	105,372	105,950	106,870	107,920
B. Additional Forecast																			
Future BTM(6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response(5)	-660	-727	-801	-945	-1,014	-1,166	-1,395	-1,524	-1,580	-1,596	-1,594	-1,586	-1,598	-1,612	-1,606	-1,590	-1,589	-1,578	-1,586
D. Demand Response-Existing(2)(3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	83,386	87,650	86,277	87,841	89,420	91,534	93,498	95,905	96,798	97,751	98,760	100,094	100,827	101,657	102,554	103,782	104,361	105,292	106,334
F. % Increase in Adjusted Energy	-0.9%	5.1%	-1.6%	1.8%	1.8%	2.4%	2.1%	2.6%	0.9%	1.0%	1.0%	1.4%	0.7%	0.8%	0.9%	1.2%	0.6%	0.9%	1.0%

Notes: 1) Actual metered data.

2) Demand response programs are classified as capacity resources and are not included in adjusted load.

3) Historical numbers include existing DSM programs. For forecasted numbers, the Company included adjustments for energy efficiency, retail choice, and voltage optimization as discussed in Sections 4.1.3, 4.1.4, and 4.1.5 of the Plan, which are not included in the above numbers.

4) Actual historical data based on measured and verified EM&V results.

5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

6) Future behind-the-meter, which is not included in the base forecast.

Appendix 4I - Required Reserve Margin for Plan B

Company Name: Virginia Electric and Power Company **Schedule 6**

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Reserve Margin(1)																			
1. Summer Reserve Margin																			
a. MW(1)	3,799	2,946	3,399	3,480	3,387	2,746	2,125	2,042	1,846	2,500	3,305	3,523	3,898	4,568	4,767	5,149	5,249	6,413	6,638
b. Percent of Load	23.2%	17.8%	20.5%	21.2%	20.4%	16.3%	12.5%	11.9%	10.7%	14.3%	18.9%	19.9%	21.8%	25.4%	26.3%	28.2%	28.3%	34.3%	35.3%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	20.0%	18.6%	14.8%	10.4%	9.4%	7.7%	11.1%	15.0%	16.3%	18.4%	21.9%	22.7%	24.4%	25.1%	31.2%	32.3%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	4,343	4,170	3,095	2,025	1,525	829	1,154	1,668	1,311	1,200	1,518	1,229	1,316	1,057	1,884	1,735
b. Percent of Load	N/A	N/A	N/A	26.3%	25.0%	18.1%	11.6%	8.6%	4.6%	6.4%	9.2%	7.1%	6.5%	8.2%	6.5%	6.9%	5.5%	9.7%	8.9%
c. Actual Reserve Margin(2)	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
II. Annual Loss-of-Load Hours(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

Notes: 1) Calculated based on total net capacity for summer and winter.
2) Does not include spot purchases of capacity or energy efficiency programs.
3) The Company follows PJM reserve requirements, which are based on loss of load expectation.

Appendix 4J – Summer and Winter Peak for Plan B

Company Name: Virginia Electric and Power Company **Schedule 5**

POWER SUPPLY DATA

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	16,241	16,409	16,464	16,389	16,612	16,846	17,053	17,213	17,294	17,432	17,493	17,689	17,843	17,964	18,112	18,279	18,523	18,672	18,792
b. Other Commitments(2)	109	119	135	144	190	259	345	431	513	572	676	634	613	637	648	697	599	579	565
c. Total System Summer Peak	16,350	16,528	16,599	16,533	16,802	17,105	17,399	17,644	17,807	18,004	18,170	18,323	18,456	18,601	18,759	18,977	19,121	19,251	19,357
d. Percent Increase in Total Summer Peak	-3.3%	1.1%	0.4%	-0.4%	1.6%	1.8%	1.7%	1.4%	0.9%	1.1%	0.9%	0.8%	0.7%	0.8%	0.9%	1.2%	0.8%	0.7%	0.6%
2. Winter																			
a. Adjusted Winter Peak(1)	16,509	17,673	16,707	16,497	16,664	17,140	17,419	17,670	17,936	18,032	18,068	18,429	18,593	18,580	18,867	18,983	19,241	19,385	19,538
b. Other Commitments(2)	109	119	135	240	340	216	292	404	512	589	739	579	575	791	670	693	598	589	582
c. Total System Winter Peak	16,618	17,792	16,842	16,737	17,004	17,356	17,711	18,074	18,448	18,621	18,807	19,008	19,168	19,371	19,537	19,676	19,839	19,974	20,120
d. Percent Increase in Total Winter Peak	2.8%	7.1%	-5.3%	-0.6%	1.6%	2.1%	2.0%	2.0%	2.1%	0.9%	1.0%	1.1%	0.8%	1.1%	0.9%	0.7%	0.8%	0.7%	0.7%

Notes: 1) Adjusted load from Appendix 4H.
2) Includes firm Additional Forecast, Conservation Efficiency, and Peak Adjustments from Appendix 4H.

Appendix 4K – Wholesale Power Sales Contracts

Company Name: Virginia Electric and Power Company **Schedule 20**

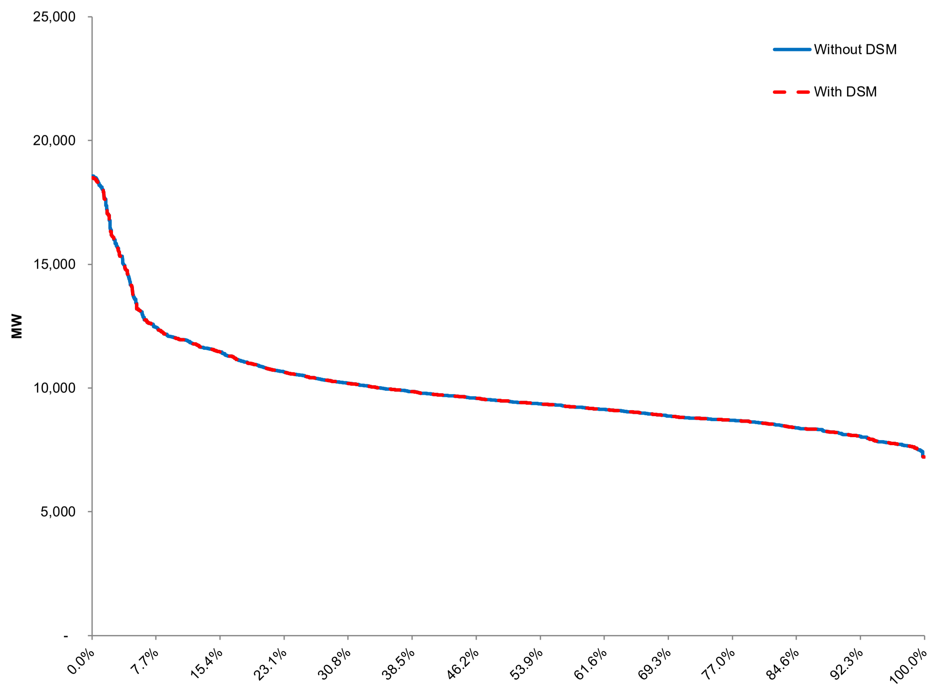
WHOLESALE POWER SALES CONTRACTS

Entity	Contract Length	Contract Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
				(Actual)								(Projected)									
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11	11
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	11	11	12	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements[1]	299	299	300	300	300	301	302	302	303	303	304	305	305	306	306	307	308	308	309

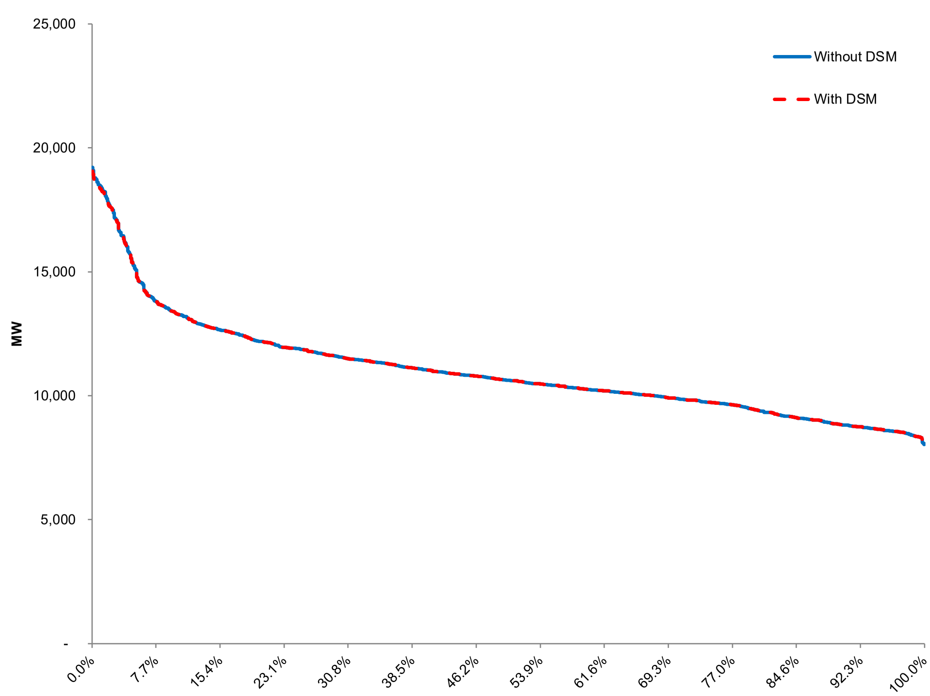
Notes: 1) Full requirements contracts do not have a specific contracted capacity amount. MW are included in the Company's load forecast.

Appendix 4L – Load Duration Curves

2020 Load Duration Curve

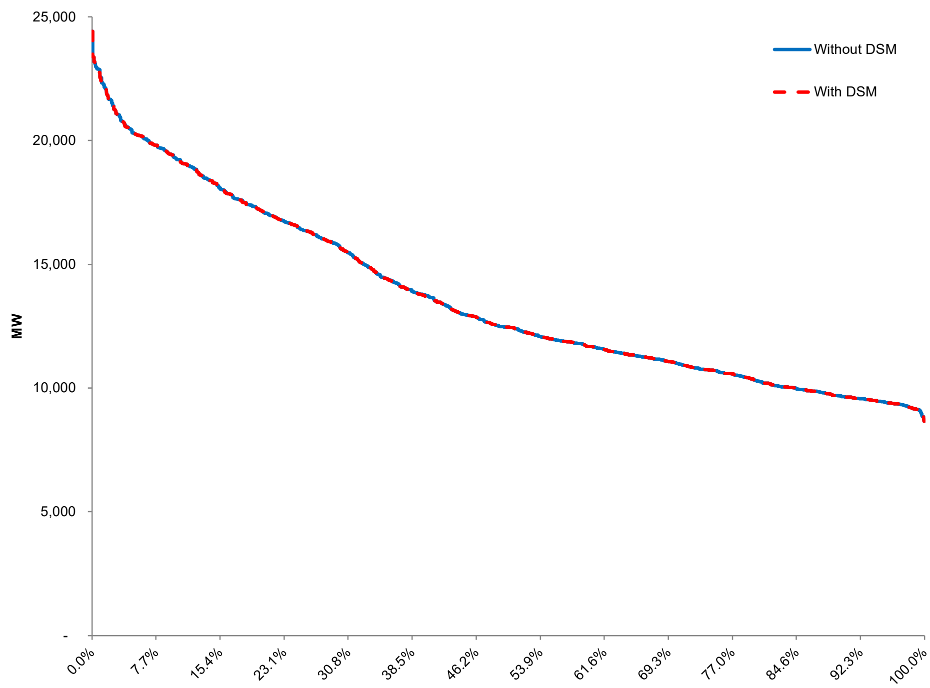


2025 Load Duration Curve



Appendix 4L cont. – Load Duration Curves

2035 Load Duration Curve



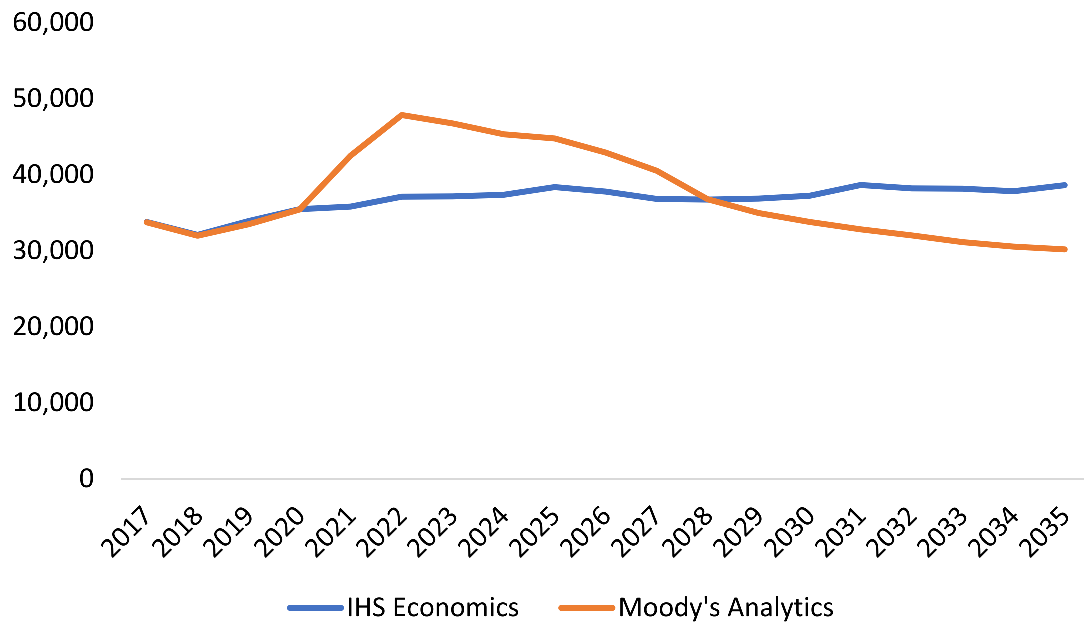
Appendix 4M – Economic Assumptions used in the Sales and Hourly Budget Forecast Model
(Annual Growth Rate)

	Economic Assumptions Used In the Sales and Hourly Budget Forecst Model (Annual Growth Rate)																
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	CAGR
Population: Total, (Ths.)	8,627	8,678	8,732	8,786	8,840	8,893	8,945	8,995	9,042	9,088	9,133	9,177	9,219	9,261	9,301	9,341	0.5%
Disposable Personal Income: (Mil. 09$; SAAR)	411,989	414,609	425,299	434,774	443,853	454,329	464,042	474,722	488,393	502,614	516,704	530,667	543,983	556,779	569,412	582,343	2.3%
Per Capia Disposable Personal Income: (C 09$; SAAR)	47.8	47.8	48.7	49.5	50.2	51.1	51.9	52.8	54.0	55.3	56.6	57.8	59.0	60.1	61.2	62.3	1.8%
Residential Permits: Total, (#, SAAR)	34,610	41,225	47,372	46,251	44,853	44,285	42,485	40,085	36,380	34,590	33,403	32,441	31,663	30,776	30,190	29,852	-1.0%
Employment: Total Manufacturing, (Ths., SA)	244	239	236	233	229	226	224	221	219	216	214	211	209	207	204	202	-1.3%
Employment: Total Government, (Ths., SA)	728	729	734	739	744	750	755	761	766	772	778	784	788	792	796	800	0.6%
Employment: Military personnel, (Ths., SA)	136	135	134	134	133	133	132	132	131	131	131	130	130	129	129	128	-0.4%
Employment: State and local government, (Ths., SA)	545	547	551	556	562	567	572	578	583	589	595	600	604	608	612	616	0.8%
Employment: Commercial Sector, (Ths., SA)	2,886	2,889	2,919	2,944	2,966	2,990	3,016	3,042	3,071	3,092	3,113	3,133	3,153	3,172	3,191	3,211	0.7%
Gross State Product: Total Manufacturing, (Bil. Ch. 2009 USD, SAAR)	43.4	44.1	45.2	45.6	46.1	46.5	46.9	47.4	48.0	48.6	49.1	49.6	50.2	50.8	51.5	52.1	1.2%
Gross State Product: Total, (Bil. Ch. 2009 USD, SAAR)	497	507	521	532	543	553	562	573	584	595	605	615	626	637	648	659	1.9%
Gross State Product: State and Local Government,(Bil. Chained 2005 $, SAAR)	38.1	38.5	39.2	39.9	40.5	41.1	41.6	42.2	42.8	43.3	43.7	44.2	44.6	45.0	45.4	45.8	1.2%

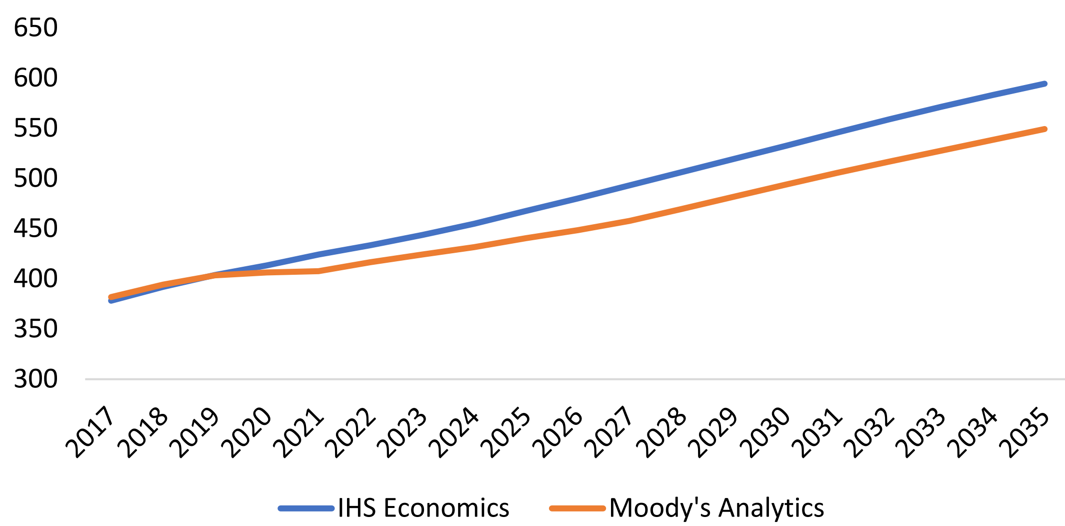
Source: Moody's Analytic Vintage October 2019

Appendix 4N – Comparison of Moody's and IHS

Total Housing Permits

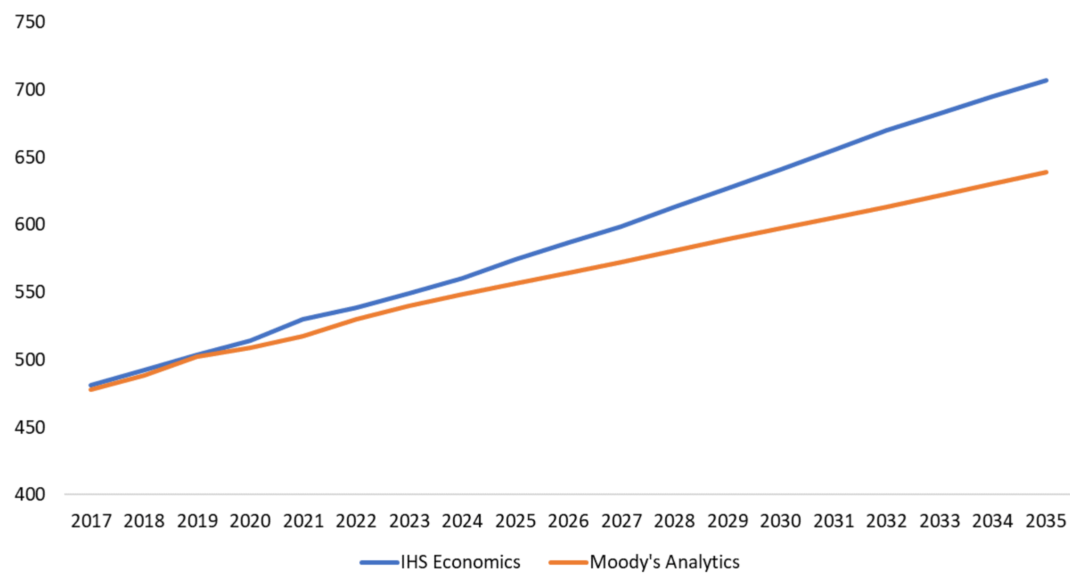


Real Disposable Income ($000)

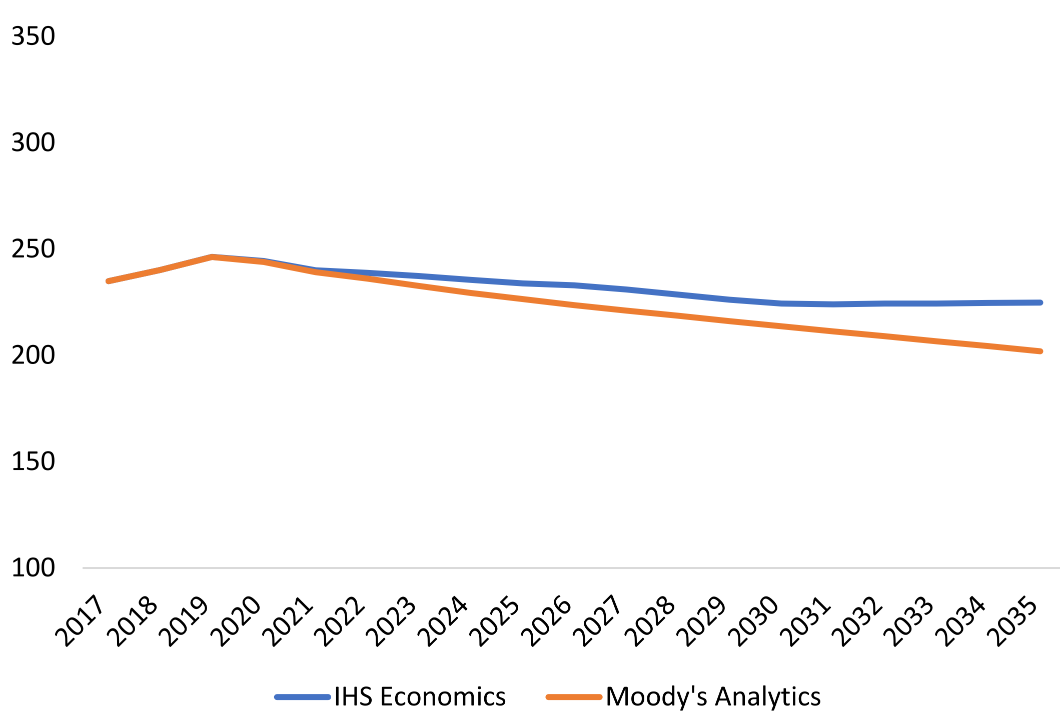


Appendix 4N cont. – Comparison of Moody's and IHS

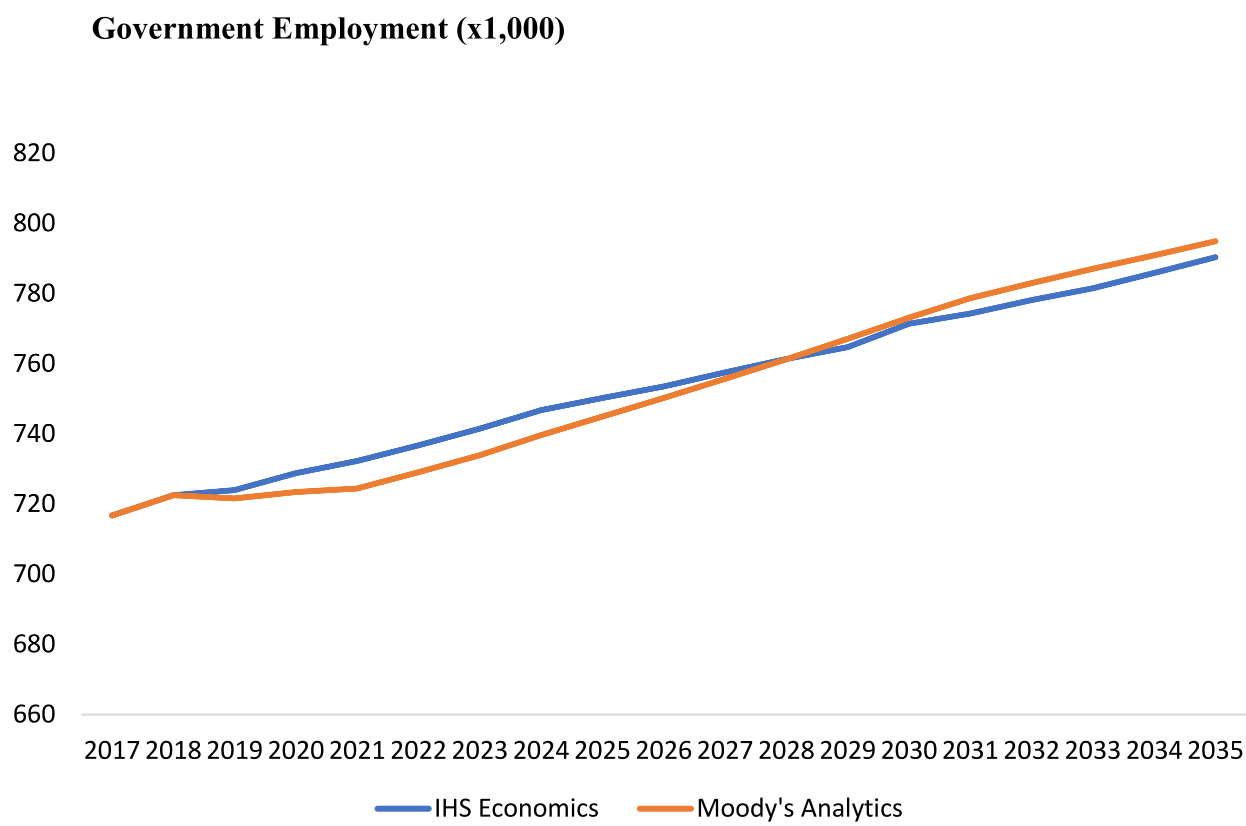
Virginia Gross State Product



Manufacturing Employment



Appendix 4N cont. – Comparison of Moody's and IHS



Appendix 4O
ICF Commodity Price Forecasts for Virginia Electric and Power Company

Fall 2019 Forecast

NOTICE PROVISIONS FOR AUTHORIZED THIRD PARTY USERS.

ICF Mid-Case Federal CO_2 with Virginia in RGGI Forecast (Nominal $)

	Fuel Price					Power and REC Prices			RTO Capacity Prices		Emission Prices			
Year	Henry Hub Natural Gas ($/MMBtu)	Zone 5 Delivered Natural Gas ($/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)	($/kW-yr)	($/MW-day)[1]	CSAPR SO_2 ($/ton)	CSAPR Ozone NO_x ($/ton)	CSAPR Annual NO_x ($/ton)	CO_2 ($/ton)
2020	2.29	2.54	1.96	14.26	10.75	32.49	24.01	9.43	31.50	86.31	3.54	103.68	3.54	0.00
2021	2.49	2.90	2.14	13.62	9.55	34.55	26.05	9.38	41.45	113.55	3.54	98.36	3.54	5.05
2022	2.95	3.01	2.46	13.20	8.71	37.65	28.96	8.48	51.31	140.59	3.33	35.69	3.33	5.29
2023	3.29	2.96	2.66	13.62	8.44	38.68	29.75	8.47	52.48	143.78	3.24	3.24	3.24	5.54
2024	3.38	2.90	2.72	14.46	9.03	38.35	29.65	9.72	53.50	146.57	3.30	3.30	3.30	5.80
2025	3.48	3.00	2.79	15.26	9.58	40.49	31.38	11.93	54.52	149.36	3.37	3.37	3.37	6.07
2026	3.69	3.30	2.85	15.96	10.07	43.09	33.45	14.04	55.56	152.21	3.43	3.43	3.43	9.60
2027	3.91	3.44	2.92	16.87	10.70	43.67	34.04	12.27	56.64	155.17	3.50	3.50	3.50	9.31
2028	4.14	3.63	2.99	17.93	11.44	44.66	34.93	10.76	57.74	158.20	3.57	3.57	3.57	9.10
2029	4.37	3.88	3.06	18.98	12.18	46.30	36.32	8.73	58.88	161.32	3.64	3.64	3.64	8.94
2030	4.61	4.19	3.13	19.89	12.82	48.58	38.24	3.96	60.04	164.50	3.71	3.71	3.71	8.84
2031	4.71	4.20	3.21	20.63	13.33	48.44	38.19	5.16	61.21	167.70	3.78	3.78	3.78	9.30
2032	4.80	4.24	3.28	21.23	13.73	48.73	38.43	6.42	62.39	170.92	3.86	3.86	3.86	9.79
2033	4.90	4.44	3.36	21.76	14.08	50.93	40.09	7.75	63.59	174.23	3.93	3.93	3.93	10.31
2034	5.00	4.61	3.44	22.24	14.40	52.78	41.50	9.17	64.81	177.57	4.01	4.01	4.01	10.86
2035	5.10	4.56	3.52	22.70	14.70	51.73	40.80	10.65	66.05	180.95	4.09	4.09	4.09	11.44

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices for all commodities except capacity and CO_2 prices. 2023 and beyond are forecast prices. Capacity prices reflect PJM RPM auction clearing prices through delivery year 2021/2022, forecast thereafter. CO_2 prices reflect the price in Virginia.

1) RTO Capacity prices are restated in the units used by the PJM Capacity market.

ICF Commodity Forecast: Natural Gas

	Henry Hub Natural Gas ($/MMBtu)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	2.29	2.29	2.29	2.29
2021	2.49	2.49	2.49	2.49
2022	3.01	2.95	3.01	2.93
2023	3.34	3.29	3.34	3.28
2024	3.41	3.38	3.41	3.38
2025	3.48	3.48	3.48	3.47
2026	3.67	3.69	3.67	3.74
2027	3.87	3.91	3.87	4.02
2028	4.08	4.14	4.08	4.30
2029	4.29	4.37	4.29	4.60
2030	4.51	4.61	4.51	4.91
2031	4.61	4.71	4.60	4.87
2032	4.70	4.80	4.70	4.82
2033	4.80	4.90	4.79	4.77
2034	4.89	5.00	4.89	4.72
2035	4.99	5.10	4.98	4.66

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: Natural Gas

	Zone 5 Delivered Natural Gas ($/MMBtu)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	2.54	2.54	2.54	2.54
2021	2.90	2.90	2.90	2.90
2022	3.06	3.01	3.06	2.98
2023	3.02	2.96	3.02	3.00
2024	2.93	2.90	2.93	3.03
2025	3.00	3.00	3.00	3.12
2026	3.28	3.30	3.28	3.43
2027	3.40	3.44	3.40	3.50
2028	3.58	3.63	3.58	3.81
2029	3.81	3.88	3.81	4.03
2030	4.09	4.19	4.09	4.27
2031	4.10	4.20	4.10	4.58
2032	4.14	4.24	4.13	4.52
2033	4.34	4.44	4.33	4.42
2034	4.51	4.61	4.50	3.83
2035	4.46	4.56	4.45	4.31

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: Coal – FOB

	CAPP CSX: 12,500 1%S FOB ($/MMBtu)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	1.96	1.96	1.96	1.96
2021	2.14	2.14	2.14	2.14
2022	2.46	2.46	2.46	2.46
2023	2.66	2.66	2.66	2.65
2024	2.73	2.72	2.73	2.72
2025	2.79	2.79	2.79	2.78
2026	2.86	2.85	2.86	2.85
2027	2.93	2.92	2.93	2.92
2028	3.00	2.99	3.00	2.98
2029	3.07	3.06	3.07	3.06
2030	3.14	3.13	3.14	3.13
2031	3.22	3.21	3.22	3.20
2032	3.29	3.28	3.29	3.28
2033	3.37	3.36	3.37	3.35
2034	3.45	3.44	3.45	3.43
2035	3.53	3.52	3.53	3.51

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: Oil

	No. 2 Oil ($/MMBtu)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	14.26	14.26	14.26	14.26
2021	13.62	13.62	13.62	13.62
2022	13.20	13.20	13.20	13.20
2023	13.62	13.62	13.62	13.62
2024	14.46	14.46	14.46	14.46
2025	15.26	15.26	15.26	15.26
2026	15.96	15.96	15.96	15.96
2027	16.87	16.87	16.87	16.87
2028	17.93	17.93	17.93	17.93
2029	18.98	18.98	18.98	18.98
2030	19.89	19.89	19.89	19.89
2031	20.63	20.63	20.63	20.63
2032	21.23	21.23	21.23	21.23
2033	21.76	21.76	21.76	21.76
2034	22.24	22.24	22.24	22.24
2035	22.70	22.70	22.70	22.70

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: Oil

	1% No.6 Oil ($/MMBtu)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	10.75	10.75	10.75	10.75
2021	9.55	9.55	9.55	9.55
2022	8.71	8.71	8.71	8.71
2023	8.44	8.44	8.44	8.44
2024	9.03	9.03	9.03	9.03
2025	9.58	9.58	9.58	9.58
2026	10.07	10.07	10.07	10.07
2027	10.70	10.70	10.70	10.70
2028	11.44	11.44	11.44	11.44
2029	12.18	12.18	12.18	12.18
2030	12.82	12.82	12.82	12.82
2031	13.33	13.33	13.33	13.33
2032	13.73	13.73	13.73	13.73
2033	14.08	14.08	14.08	14.08
2034	14.40	14.40	14.40	14.40
2035	14.70	14.70	14.70	14.70

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: On-Peak Power Price

	PJM-DOM On-Peak ($/MWh)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	32.49	32.49	32.49	32.49
2021	34.54	34.55	34.58	34.51
2022	37.61	37.65	38.01	37.06
2023	38.66	38.68	39.19	37.52
2024	38.29	38.35	38.79	37.81
2025	40.33	40.49	40.84	38.88
2026	42.44	43.09	42.90	44.52
2027	42.51	43.67	42.90	47.17
2028	42.94	44.66	43.27	53.13
2029	44.00	46.30	44.24	56.27
2030	45.64	48.58	45.79	63.37
2031	45.42	48.44	45.55	69.91
2032	45.62	48.73	45.72	70.05
2033	47.62	50.93	47.73	69.21
2034	49.31	52.78	49.38	60.07
2035	48.19	51.73	48.26	68.39

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: Off-Peak Power Price

	PJM-DOM Off-Peak ($/MWh)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	24.01	24.01	24.01	24.01
2021	26.06	26.05	26.07	26.03
2022	29.00	28.96	29.25	28.51
2023	29.81	29.75	30.16	28.73
2024	29.65	29.65	30.00	28.98
2025	31.29	31.38	31.65	29.85
2026	32.94	33.45	33.28	34.60
2027	33.09	34.04	33.37	37.17
2028	33.50	34.93	33.74	42.28
2029	34.40	36.32	34.58	45.15
2030	35.75	38.24	35.87	51.27
2031	35.65	38.19	35.74	56.41
2032	35.81	38.43	35.87	56.48
2033	37.32	40.09	37.37	55.69
2034	38.59	41.50	38.62	48.45
2035	37.84	40.80	37.84	55.00

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: PJM Tier 1 Renewable Energy Certificates

	PJM Tier 1 REC Prices ($/MWh)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	9.43	9.43	9.43	9.43
2021	9.38	9.38	9.38	9.38
2022	8.51	8.48	8.46	8.58
2023	8.53	8.47	8.39	8.80
2024	9.83	9.72	9.70	10.21
2025	12.20	11.93	12.01	12.27
2026	14.70	14.04	14.36	13.22
2027	13.34	12.27	13.06	8.29
2028	12.25	10.76	12.04	4.08
2029	10.64	8.73	10.48	3.88
2030	3.96	3.96	3.96	3.96
2031	5.70	5.16	5.65	4.04
2032	7.56	6.42	7.43	4.11
2033	9.52	7.75	9.33	4.19
2034	11.58	9.17	11.33	4.28
2035	13.77	10.65	13.44	4.36

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: PJM RTO Capacity

	RTO Capacity Prices ($/kW-yr)			
Year	No CO_2 Tax Commodity Forecast	Mid-case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	31.50	31.50	31.50	31.50
2021	41.45	41.45	41.45	41.45
2022	51.35	51.31	51.32	51.31
2023	52.59	52.48	52.50	52.47
2024	53.69	53.50	53.54	53.49
2025	54.78	54.52	54.57	54.50
2026	55.90	55.56	55.63	55.54
2027	57.07	56.64	56.73	56.61
2028	58.26	57.74	57.85	57.71
2029	59.49	58.88	59.01	58.85
2030	60.74	60.04	60.19	60.00
2031	62.00	61.21	61.37	61.16
2032	63.28	62.39	62.57	62.33
2033	64.59	63.59	63.80	63.53
2034	65.92	64.81	65.04	64.74
2035	67.26	66.05	66.30	65.97

Note: PJM RPM auction clearing prices through delivery year 2021/22, forecast thereafter.

ICF Commodity Forecast: PJM RTO Capacity

	RTO Capacity Prices ($/MW-day)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	86.31	86.31	86.31	86.31
2021	113.55	113.55	113.55	113.55
2022	140.70	140.59	140.61	140.58
2023	144.09	143.78	143.85	143.76
2024	147.08	146.57	146.68	146.54
2025	150.09	149.36	149.51	149.32
2026	153.16	152.21	152.41	152.15
2027	156.35	155.17	155.41	155.10
2028	159.61	158.20	158.49	158.11
2029	162.98	161.32	161.66	161.22
2030	166.42	164.50	164.90	164.38
2031	169.88	167.70	168.14	167.56
2032	173.38	170.92	171.43	170.77
2033	176.97	174.23	174.79	174.06
2034	180.60	177.57	178.19	177.38
2035	184.28	180.95	181.63	180.74

Note: RTO Capacity prices are restated in the units used by the PJM Capacity market. PJM RPM auction clearing prices through delivery year 2021/22, forecast thereafter.

ICF Commodity Forecast: SO_2 Emission Allowances

	CSAPR SO_2 (\$/Ton)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	3.54	3.54	3.54	3.54
2021	3.54	3.54	3.54	3.54
2022	3.33	3.33	3.33	3.33
2023	3.24	3.24	3.24	3.24
2024	3.30	3.30	3.30	3.30
2025	3.37	3.37	3.37	3.37
2026	3.43	3.43	3.43	3.43
2027	3.50	3.50	3.50	3.50
2028	3.57	3.57	3.57	3.57
2029	3.64	3.64	3.64	3.64
2030	3.71	3.71	3.71	3.71
2031	3.78	3.78	3.78	3.78
2032	3.86	3.86	3.86	3.86
2033	3.93	3.93	3.93	3.93
2034	4.01	4.01	4.01	4.01
2035	4.09	4.09	4.09	4.09

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: NO_x Emission Allowances

	CSAPR Ozone NOx ($/Ton)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	103.68	103.68	103.68	103.68
2021	98.36	98.36	98.36	98.36
2022	35.69	35.69	35.69	35.69
2023	3.24	3.24	3.24	3.24
2024	3.30	3.30	3.30	3.30
2025	3.37	3.37	3.37	3.37
2026	3.43	3.43	3.43	3.43
2027	3.50	3.50	3.50	3.50
2028	3.57	3.57	3.57	3.57
2029	3.64	3.64	3.64	3.64
2030	3.71	3.71	3.71	3.71
2031	3.78	3.78	3.78	3.78
2032	3.86	3.86	3.86	3.86
2033	3.93	3.93	3.93	3.93
2034	4.01	4.01	4.01	4.01
2035	4.09	4.09	4.09	4.09

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

ICF Commodity Forecast: NO_x Emission Allowances

	CSAPR Annual NOx ($/Ton)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	3.54	3.54	3.54	3.54
2021	3.54	3.54	3.54	3.54
2022	3.33	3.33	3.33	3.33
2023	3.24	3.24	3.24	3.24
2024	3.30	3.30	3.30	3.30
2025	3.37	3.37	3.37	3.37
2026	3.43	3.43	3.43	3.43
2027	3.50	3.50	3.50	3.50
2028	3.57	3.57	3.57	3.57
2029	3.64	3.64	3.64	3.64
2030	3.71	3.71	3.71	3.71
2031	3.78	3.78	3.78	3.78
2032	3.86	3.86	3.86	3.86
2033	3.93	3.93	3.93	3.93
2034	4.01	4.01	4.01	4.01
2035	4.09	4.09	4.09	4.09

Note: The 2020 - 2022 prices are a blend of futures/forwards and forecast prices. 2023 and beyond are forecast prices.

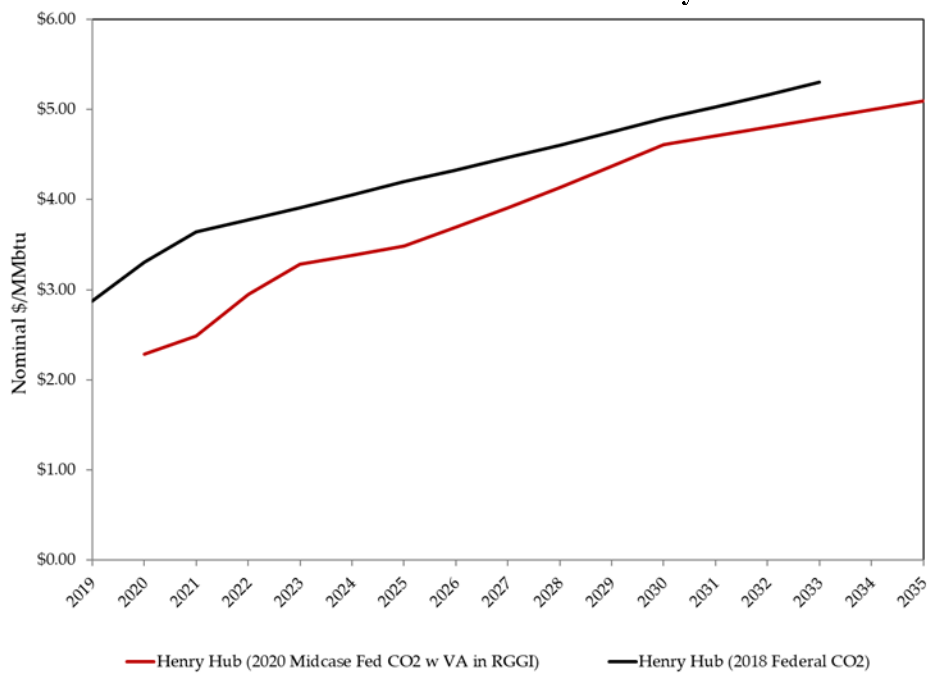
ICF Commodity Forecast: CO_2

	CO_2 ($/Ton)			
Year	No CO_2 Tax Commodity Forecast	Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast	Virginia in RGGI Commodity Forecast	High-Case Federal CO_2 Commodity Forecast
2020	0.00	0.00	0.00	0.00
2021	0.00	5.05	5.09	0.00
2022	0.00	5.29	5.33	0.00
2023	0.00	5.54	5.58	0.00
2024	0.00	5.80	5.84	0.00
2025	0.00	6.07	6.11	0.00
2026	0.00	9.60	6.26	0.00
2027	0.00	9.31	6.28	0.00
2028	0.00	9.10	6.31	30.13
2029	0.00	8.94	6.33	32.14
2030	0.00	8.84	6.35	34.29
2031	0.00	9.30	6.66	36.57
2032	0.00	9.79	6.97	38.99
2033	0.00	10.31	7.30	41.58
2034	0.00	10.86	7.65	44.33
2035	0.00	11.44	8.01	47.26

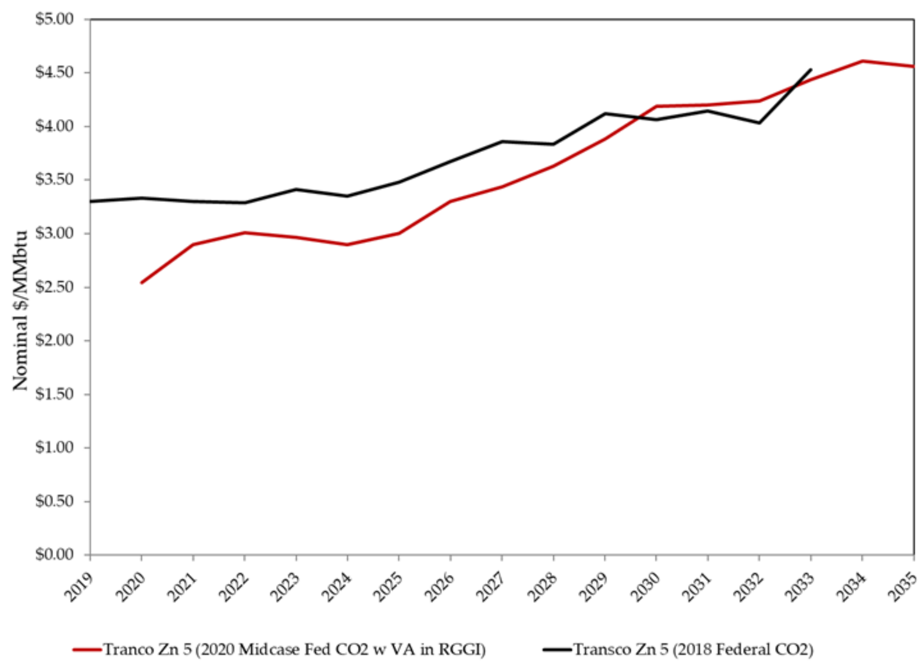
Note: The CO_2 prices are reflective of the price in Virginia.

Appendix 4P – ICF Price Forecasts

Fuel Price Forecast – Natural Gas Henry Hub

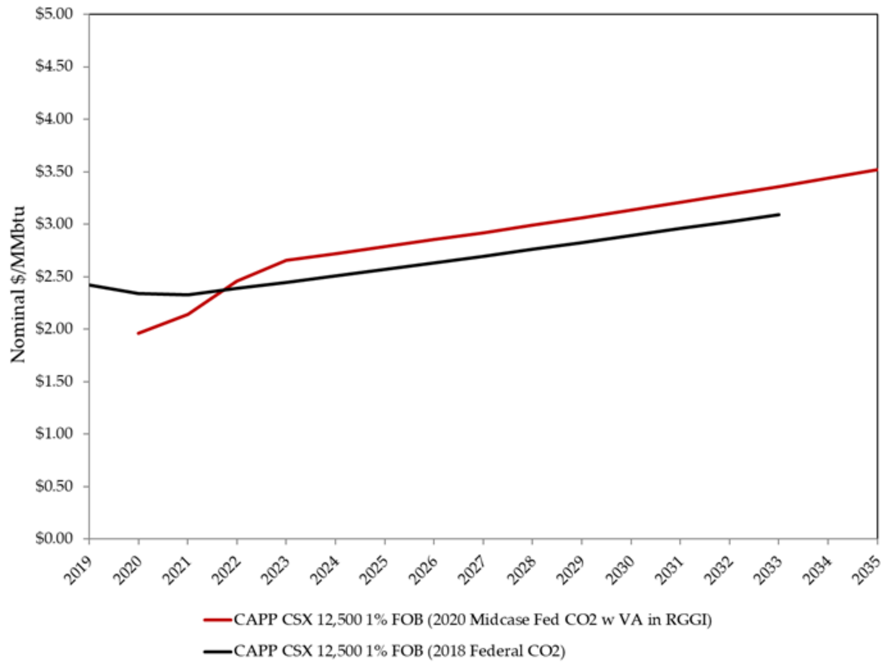


Fuel Price Forecast – Natural Gas Transco Zone 5

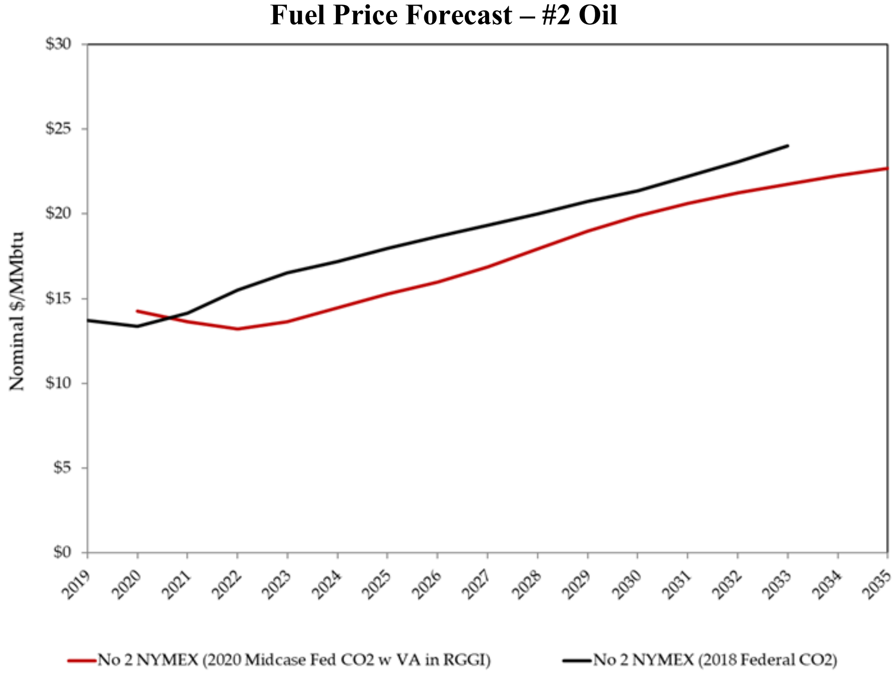


Appendix 4P cont. – ICF Price Forecasts

Fuel Price Forecast – Coal

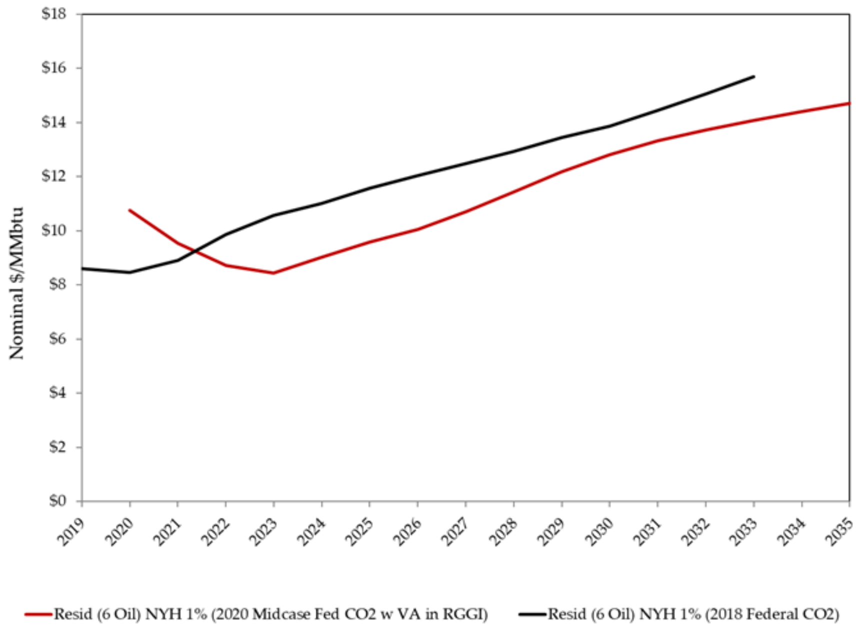


Fuel Price Forecast – #2 Oil

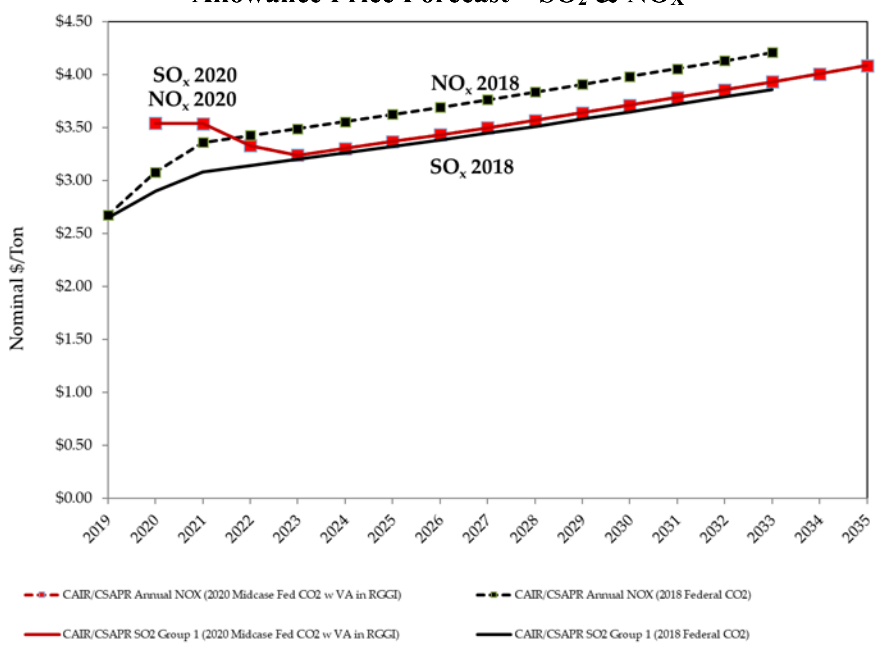


Appendix 4P cont. – ICF Price Forecasts

Fuel Price Forecast – #6 Oil

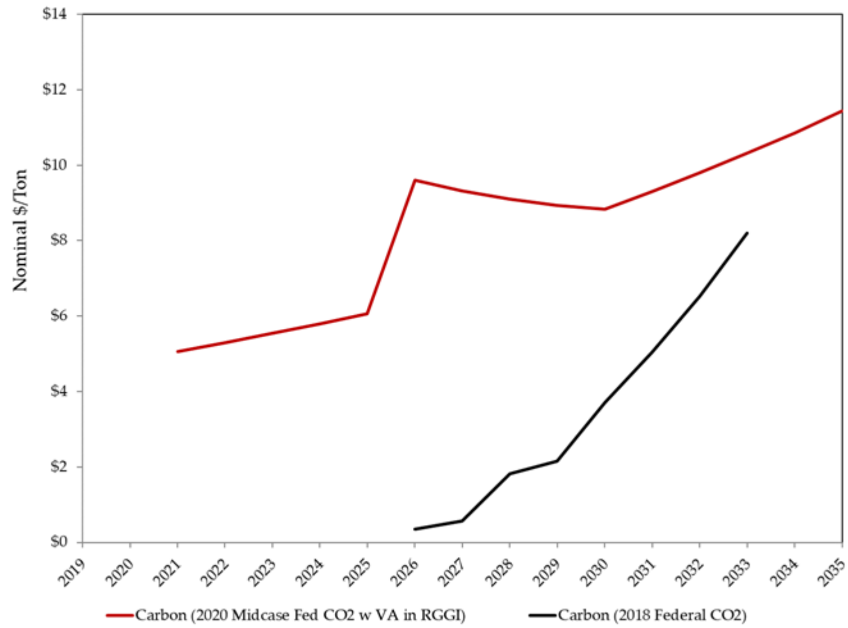


Allowance Price Forecast – SO_2 & NO_X



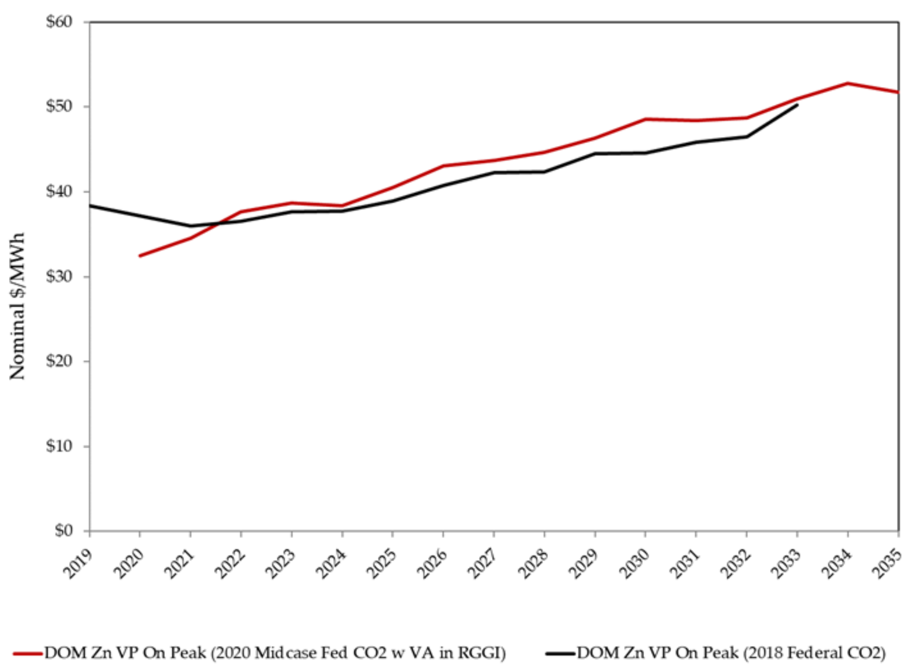
Appendix 4P cont. – ICF Price Forecasts

Allowance Price Forecast – CO_2



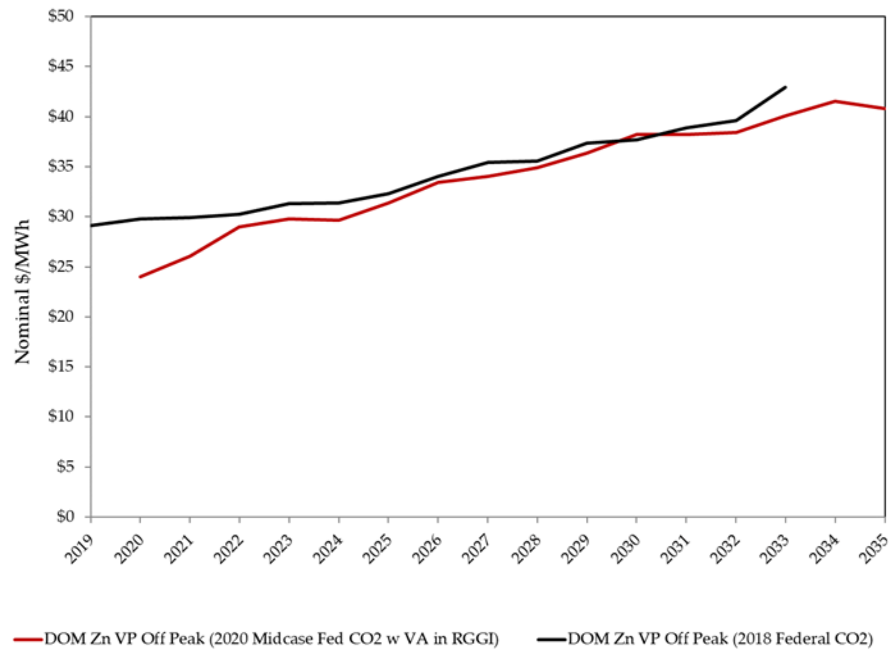
Note: The Federal CO_2 commodity forecast used in the 2018 Plan included a CO_2 allowance price beginning in 2026 on a per ton basis. The Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast used in the 2020 Plan utilizes the RGGI allowance.

Power Price Forecast – On-Peak Power

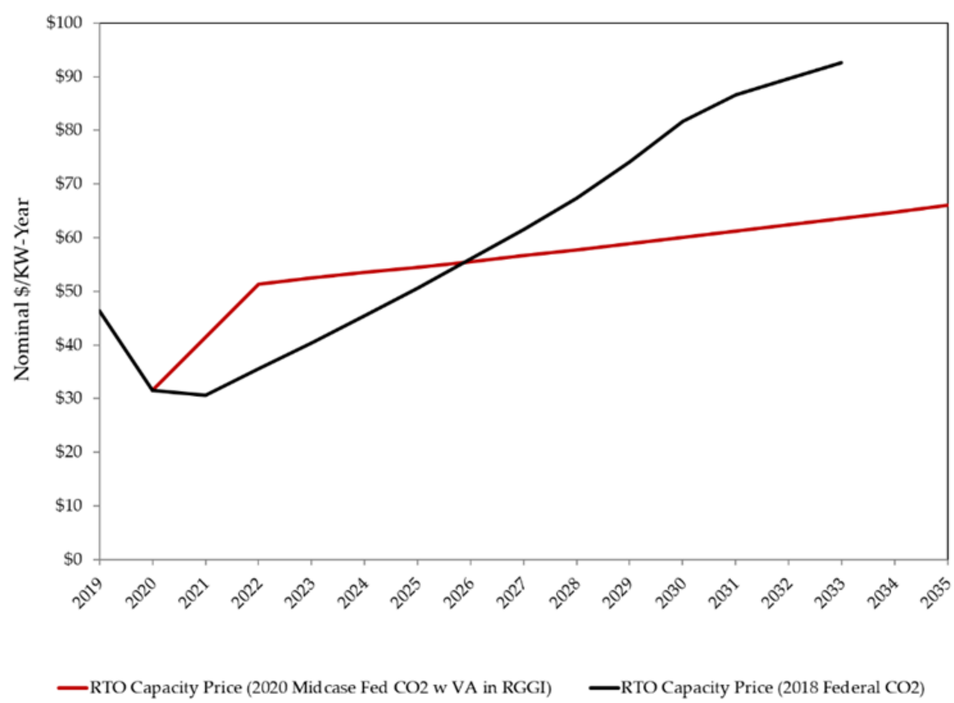


Appendix 4P cont. – ICF Price Forecasts

Power Price Forecast – Off-Peak Power



PJM RTO Capacity Price Forecast



Overview of PJM REC Price Forecasting

March 2020

Prepared For:
Dominion Energy Virginia

Prepared by:
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PJM Market Background

The PJM power market includes nine states or areas with sizeable Renewable Portfolio Standards (RPS). The standards—in Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington DC—require an escalating portion of retail sales be met through qualified renewable energy (RE) generation.[1] Additionally, Indiana has voluntary targets.

Load serving entities in the PJM region comply with their relevant RPS obligations via Renewable Energy Credits (RECs), where one credit represents one MWh of qualifying generation. RECs are tradeable and have varying values depending on the state. Many states have multiple types of RECs, including Tier I, Tier II and solar carve-out RECs (or SRECs). Of these, SRECs and Tier I RECs are typically the most valuable. Of the PJM states with mandatory RPS requirements, all but Michigan require that a minimum percent of their load be supplied by solar energy, known as a solar carve-out. More recently, several states in the U.S. have added targets for offshore wind within their renewable goals. Within PJM, Maryland and New Jersey have done so. The current RPS mandates for each PJM state are shown in Exhibit 1.

Exhibit 1: Current State Level RPS Targets

State	Tier I Target	Solar Carve-out	Offshore Wind Buildout
New Jersey	50% by 2030	5.1% by 2021, TBD by 2030	3,500 MW by 2030
Pennsylvania	8% by 2021	0.5% by 2021	N/A
Maryland	50% by 2030	14.5% by 2028	1,568 MW by 2030
Delaware	25% by 2025	3.5% by 2025	N/A
Ohio	8.5% by 2026	N/A	N/A
Washington, D.C.	100% by 2032	10% by 2041	N/A
Illinois[1]	25% by 2026	4 million RECs by 2030	N/A
Michigan[1,2]	15% by 2021	N/A	N/A
North Carolina[1]	12.5% by 2021	0.2% by 2018	N/A

[1] Only part of the state falls within the PJM footprint.

[2] Michigan utilities Consumers and DTE have committed to 25% renewable energy by 2030.

The ICF Forecasting methodology for REC pricing begins with a fundamentals view of the PJM market, through assessing the drivers of supply and demand for RECs. For the 2020 IRP forecast for Dominion Energy Virginia ("Dominion"), ICF has expanded this fundamentals approach to better capture the uncertainty in REC markets by creating a weighted price forecast considering alternate forward looking renewable market scenarios. Below is a discussion of the fundamentals modeling approach, which is used within each of the scenario modeling, followed by a discussion of the RPS sensitivities and weighting methodology used to capture uncertainty.

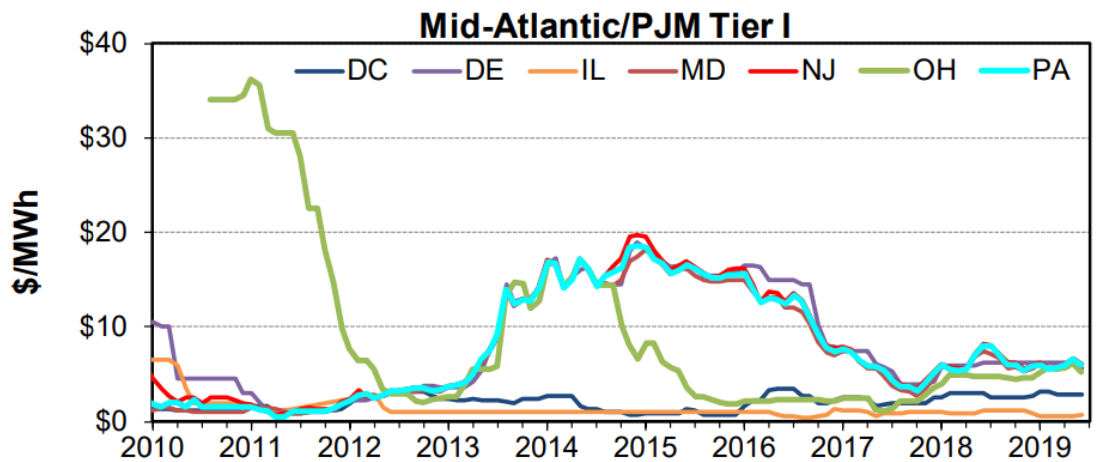
[1] In March 2020 the Virginia General Assembly passed the Virginia Clean Economy Act, mandating 100% clean energy by 2045 for Phase II Utilities and by 2050 for Phase I Utilities. This legislation was not included in the modeling.

ICF Fundamental Modeling for REC pricing

Demand

ICF models the PJM RPS demand using state level RPS requirements and provides a Mid-Atlantic PJM Tier 1 REC price forecast to Dominion. The PJM Tier I trading market is represented by New Jersey, Pennsylvania, Maryland, Delaware, Ohio and D.C. REC markets. Due to overlapping generator eligibility criteria, these states typically coalesce into one REC trading market with similar clearing prices, as shown in Exhibit 2. The Tier I market reflects the RPS demand net of the solar carve-outs, which are supplied in a separate compliance market using SRECs. REC prices typically represent the gap between the costs of a new renewable facility and the revenues they receive from energy and capacity markets.

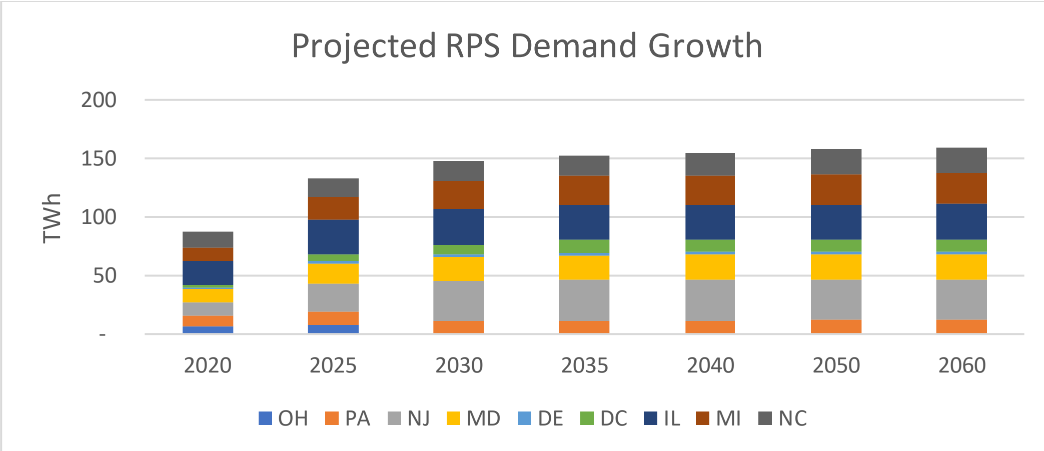
Exhibit 2: Historical PJM Tier I REC Market Trading Prices



Source: [Lawrence Berkeley National Labs, U.S. Renewable Portfolio Standards 2019 Annual Status Report](#).

The demand for PJM Tier I RECs is equal to the retail sales of eligible load-serving entities (LSE) in each state, multiplied by the RPS requirement. In its BAU Case, ICF models fully promulgated renewable portfolio standards (i.e. no proposed or speculative goals are used to establish the BAU case). ICF assumes that once a state reaches its terminal target (see Exhibit 1), the percent target remains flat over time. The latest terminal target within the Mid-Atlantic States is 2032. Beyond the point at which the terminal targets are met, changes in the demand for RECs are driven only by load growth. ICF relies on the PJM 2019 load forecast as the basis for the load growth which is used to determine RPS demand requirements. Exhibit 3 provides the BAU Case RPS demand by state over time.

Exhibit 3: Projected RPS Demand[1] 2020-2050 for PJM States[2]



[1] Demand shown is Tier I net of solar carve-outs.
[2] Demand is shown at a state level; for those states only partially contained within PJM, demand outside the PJM area is included.

Each state also has an Alternative Compliance Payment (ACP) mechanism as part of its RPS program shown in Exhibit 4. ACPs effectively serve as a price ceiling on the market price for RECs and, to some extent, they act as a cap on the market demand for RECs.

Exhibit 4: State Alternative Compliance Payments

State	Tier I ACP
New Jersey	\$50/MWh
Pennsylvania	\$45/MWh
Maryland[1]	\$30/MWh
Delaware[2]	\$25/MWh
Ohio	\$45/MWh
Washington, D.C.	\$50/MWh

1 The MD ACP is \$30/MWh in 2019, reduced to \$22.35/MWh by 2030.
2 If a Delaware retail electricity supplier has paid the \$25/MWh ACP in a previous year, then the ACP increases to \$50/MWh for the second deficient year, and \$80/MWh for subsequent deficient years.

Supply

ICF's modeling of state level RPS programs specifies generator type eligibility at the program level. Geographic eligibility is also specified at the program level for each RPS program. Banked RECs are also eligible to meet RPS demand (states typically have 3-year REC lifetimes). The current supply of existing eligible resources, as well as all eligible new resources that could be built to meet incremental RPS demand based on the eligibility criteria are reflected in the ICF analysis.

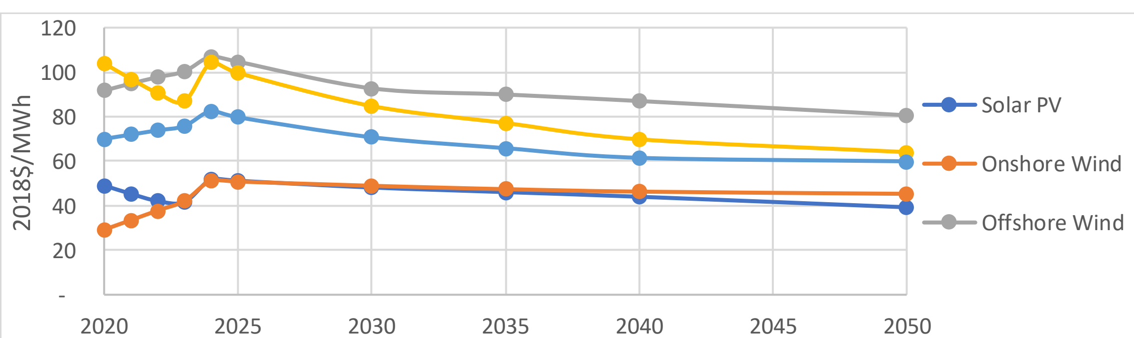
Exhibit 5 illustrates that most PJM Tier 1 RPS programs accept RECs that are generated anywhere within PJM. Some states have limitations on solar eligibility, like New Jersey, and others have more restrictive Tier I eligibility, such as Ohio.

Exhibit 5: PJM State RPS Program Eligibility

State	Tier 1 Geographic Eligibility
NJ	Located or delivered into PJM. Solar must be connected to NJ distribution grid.
MD	Located or delivered into PJM. Solar must be connected to MD distribution grid
PA	Located in PJM. Only in-state solar can meet the solar carve-out.
DE	Located or delivered into PJM. Customer sited resources must be in DE.
DC	Located in PJM. Solar must be located in the District or on a distribution feeder serving the district.
IL	Located in IL or adjoining states per IPA approval based on public interest criteria.
OH	Located or deliverable to OH.
NC	Up to 25% can be met with unbundled out of state RECs.
MI	Located in MI or in the retail electric service territory of a utility recognized by the Michigan PSC.

ICF uses the Integrated Planning Model (IPM®) to determine the least-cost build compliance scenario to supply PJM RPS demand. IPM has a choice of multiple new resource options, including solar, onshore wind, offshore wind and biomass, each with projections for cost and performance defined through 2060. For onshore and offshore wind, multiple technology resource groups are allowed as resource options. These resource groups reflect differing cost and performance characteristics for facilities in a given state. Each resource group has a maximum resource potential that the model can build to before it must turn to a different resource group. As such, IPM can choose the optimal resource mix within a technology option. Exhibit 6 illustrates the annual assumed levelized cost of energy (LCOE) of select new renewable capacity options by vintage. As shown, onshore wind resources reflect the most economic option in the near-term given the ability to take advantage of production tax credits. However, with the phase-out of the production tax credit (PTC) for wind generators, solar becomes more economic after 2025. ICF relies on the National Renewable Energy Lab (NREL) as the source for renewable resource costs over time.

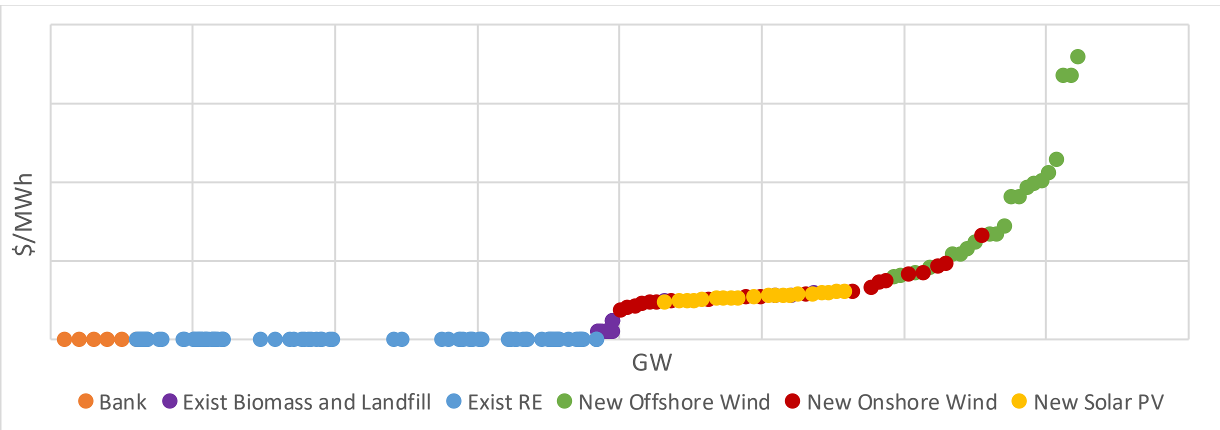
Exhibit 6: Illustrative LCOE for New Renewable Resources in PJM[1,2]



1. Federal tax credits are included with a 4-year safe harbor assumption. Offshore wind is assumed to take the ITC in lieu of the PTC.
2. Storage costs are approximated and do not reflect storage cycles or degradation.

In shortage periods, IPM will determine the appropriate units to build and dispatch resources as needed to meet RPS demand requirements, which are specified at the state level in the model. The cost of supply is based on capital and operating expense assumptions, while the quantity of supply is based on the performance assumptions for resources, which vary by location. The costs of generation capture the capital (including investment return) and fixed operating expenses based on the generator type and location. These costs are reduced by the potential for generation to earn credit for their energy and capacity sales. Exhibit 7 shows an illustrative depiction of the PJM RPS supply curve in IPM for a given year, including the option of using banked RECs. The supply curve varies yearly, as the relative economics of new wind and solar builds change over time due to declining capital costs and the expiration of tax credits.

Exhibit 7: Illustrative PJM RPS Supply Curve



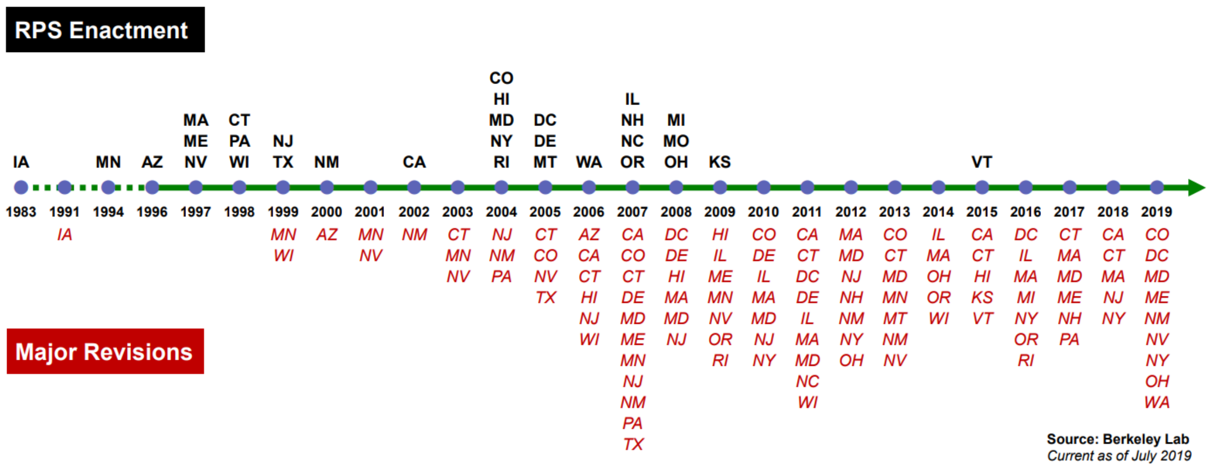
In determining alternatives to build and building the RPS supply curve, IPM further reduces the costs based on the revenue earning capabilities of the facility. That is, IPM simultaneously considers the energy and capacity value for renewable resources against the cost of each resource in order to develop the RPS supply curve utilized within IPM. As such, each facility is evaluated based on its locational costs and revenue expectations.

The PJM REC markets are thus modeled dynamically in IPM, with the model selecting the least-cost resource portfolio to meet the RPS demand. The model also considers the bankability of RECs and will temporally shift builds to minimize the cost of RPS compliance. For example, though the market may not need incremental supply in 2020 to serve the REC demand, a facility may be developed early to take advantage of the savings achievable through claiming the PTC credit. Excess credits available can then be banked for use in future years. As such, REC prices reflect the time value of the REC captured through the endogenous banking behavior in IPM.

Sensitivity Case Modeling

While the REC price forecast is estimated based on reference conditions reflecting promulgated policies, there is significant uncertainty in REC markets. Near-constant changes and refinements have defined renewable portfolio standards since near the inception of such programs. As illustrated in Exhibit 8, states have enacted changes to their RPS policies over time. States in PJM have had frequent changes in their policy goals – for example, Maryland enacted a revision 2017 as shown, and again in 2019.

Exhibit 8: State RPS Revisions



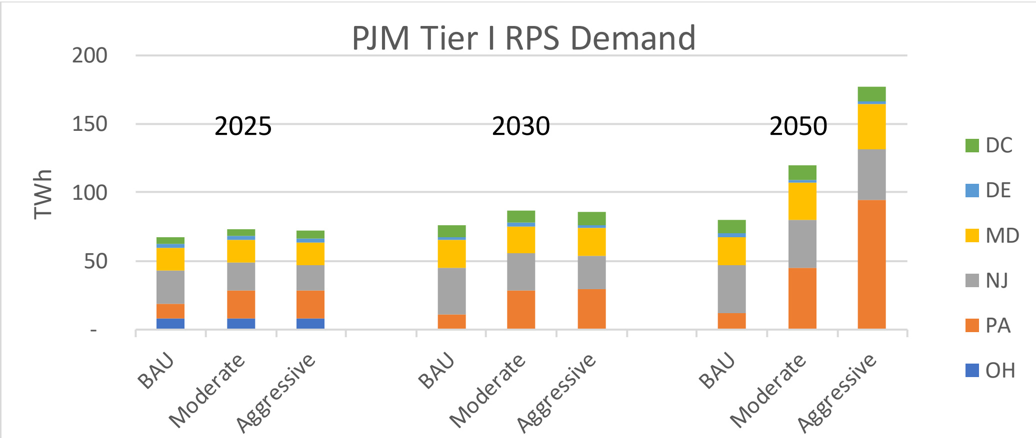
Source: Lawrence Berkeley National Labs, U.S. Renewable Portfolio Standards 2019 Annual Status Report.

Rather than rely on a single point estimate of the REC price for PJM Tier 1, ICF has adopted a methodology to account for uncertainty in the RPS policies. As such, the PJM Tier 1 REC price forecast provided to Dominion reflects a weighted average REC price forecast based on consideration of multiple possible policy outcomes. Specifically, ICF modeled three RPS scenarios to capture the regulatory uncertainty around RPS policies:

- Business As Usual (BAU) Policy Case,
- Moderate Policy Case, and
- Aggressive Policy Case

The BAU Policy Case scenario reflects current policy goals, assuming no changes to established policies over time. The Moderate Policy Case includes states taking partial action in a given direction, while the Aggressive Policy Case reflects more aggressive action taken. Exhibit 9 provides an indication of the relative demand for RECs across the three cases and additional details of each of the cases is provided in Exhibit 10 which indicates overall Tier I RPS requirement for each state, along with relevant solar carve-out requirements and offshore wind (OSW) procurement targets.

Exhibit 9: Scenario RPS Demand Comparison[1]



[1]Demand shown is Tier I net of solar carve-outs.

Exhibit 10: Scenario RPS Assumption Summary

	BAU Policy Case (No Change)	Moderate Policy Case	Aggressive Policy Case
NJ	50% by 2030 Solar: 5.1% by 2021 OSW: 3.5 GW by 2030	50% by 2030, 70% by 2050 Solar: 10% by 2030, 20% by 2050 OSW: 3.5 GW by 2030, 5 GW by 2050	50% by 2030, 85% by 2050 Solar: 15% by 2030, 30% by 2050 OSW: 3.5 by 2030, 6 GW by 2050
PA	8% by 2021 Solar: 0.5% by 2021	30% by 2030, 50% by 2050 Solar: 10% by 2030, 20% by 2050	30% by 2030, 85% by 2050 Solar: 10% by 2030, 30% by 2050
MD	50% by 2030 Solar: 14.5% by 2028 OSW: 1.5 GW by 2030	50% by 2030, 70% by 2050 Solar: 25% by 2050 OSW: 1.5 GW by 2030, 3 GW by 2050	50% by 2030, 85% by 2050 Solar: 30% by 2050 OSW: 1.5 GW by 2030, 4 GW by 2050
DE	25% by 2025 Solar: 3.5% by 2025 OSW: 0	30% by 2030, 50% by 2050 Solar: 5% by 2030, 15% by 2050 OSW: 200 MW by 2030	50% by 2030, 70% by 2050 Solar: 10% by 2030, 30% by 2050 OSW: 200 MW by 2030, 1 GW by 2050
OH	8.5% by 2026	8.5% by 2026	8.5% by 2026
D.C.	100% by 2032 Solar: 10% by 2041	No change No change	No change No change

The final ICF forecast reflects a probability weighted average of the three scenarios that reflects the likelihood of RPS policy changes over time. The probabilities consider the likelihood of specific states acting to change their RPS programs, and on what timeline they may act.

While representative of a broad range of forecast results, these cases do not capture all uncertainty. Elements not addressed include the potential for PTC/ITC extensions, costs and performance improvements for renewables, carbon price risk, market rule changes for storage, technological advances for storage, integration costs, and changes in the value of the electric load carrying capability of facilities.

Case Results

The case used for the RPS policy discussed below is the Virginia in RGGI Case, which includes no assumed federal carbon regulations and assumes that VA links with RGGI. The trends in this case are similar to those in the other cases. The Tax Credit Extension Sensitivity is discussed separately below.

Business as Usual Policy Case

In the BAU Policy Case, BAU RPS targets are modeled, where current mandatory RPS programs stay in place with no changes. This means, for example, that New Jersey's target of 50% by 2030 remains its target through 2060. The resulting BAU Policy Case PJM Tier I REC price is shown in Exhibit 11.

Exhibit 11: BAU Policy Case PJM Tier I REC (2019$/MWh)

$/REC	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
BAU	7.32	7.41	7.37	7.7	8.71	10.56	12.41	11.07	10.01	8.57	3.2	3.2	3.2	3.2	3.2

In 2020, the Tier I demand net of solar carve-outs is approximately 42 TWh. In the BAU Policy Case, Tier I RPS demand increases to approximately 77 TWh in 2030, an increase of nearly 35 TWh. A significant portion of this Tier I demand is met by mandated offshore wind capacity additions, including 3,500 MW in New Jersey and 1,568 MW in Maryland. These offshore wind projects meet approximately 57% of the incremental Tier I demand between 2020 and 2030. The remaining demand is met by a combination of new wind and solar capacity additions and increased generation from existing dispatchable resources, such as hydro and biomass.

BAU Policy Case Tier I REC prices hover around $7-9/MWh through 2024 as the PJM REC market stays in the relatively balanced state that characterizes the current market. As PTC-subsidized wind builds are removed as a cost-effective compliance option for Tier I RPS compliance, REC prices increase to continue driving new renewable resources in an environment with continued RPS demand increases. While Pennsylvania reaches its final target in 2021, targets in New Jersey, Maryland, Ohio and Delaware all continue increasing.

As such, prices increase through 2026 before declining through 2030. This is due to state-sponsored offshore wind projects beginning to come online in the two states (besides D.C.) that still have increasing RPS demand through 2030. Both New Jersey and Maryland's Tier I RPS demand increases from 2025 to 2030 are completely supplied by their respective offshore wind additions. Thus, by 2030, the PJM Tier I market is fully supplied. With no RPS percentage increases for any PJM state post 2030, the spot market price falls to just the transactional value for a compliance REC, for which ICF has used $3.20/MWh. The $3.20/MWh value is at a premium to voluntary markets due to additional compliance and reporting requirements placed on LSEs.

The Moderate Policy Case

The Moderate Policy Case RPS target assumptions (see Exhibit 10) reflect REC price risk as a result of likely policy changes in the near- and mid-term, particularly those states whose terminal years are reached prior to 2030.

In the Moderate Policy Case, the New Jersey target assumes an increase in the solar carve-out over time, a process that the state BPU is currently undertaking. Beyond the BAU target of 50% by 2030, the

Moderate Policy Case extends the program by 1%/yr, reaching 70% in 2050. The offshore wind mandate increases as well, adding an additional 1,500 MW by 2050.

The Pennsylvania target increases to 30% by 2030, with a 1%/yr increase after that to reach 50% by 2050. The interim 2030 target is based on legislation introduced in the state in 2019, SB 600, which would increase the Tier I target to 30% by 2030 and increase the solar carve-out to 10% by 2030. The 10% by 2030 target is also in line with PA DEP's Solar for the Future Plan, which outlines pathways to 10% solar penetration by 2030.

The Maryland target follows New Jersey in reaching 70% by 2050, with a slightly higher solar carve-out of 25% by 2050, consistent with a higher BAU solar carve-out. For Delaware, the Tier I target increases 1%/yr from the BAU level, and Washington, D.C. remains unchanged from the BAU, since it already has a mandate for 100% renewable energy. Ohio also remains unchanged from the BAU, with a terminal target of 8.5% by 2026.

The Aggressive Policy Case

The Aggressive Policy Case RPS target assumptions (see Exhibit 10) reflect REC price risk as a result of likely policy changes in the mid- and long-term, particularly those states with long-term decarbonization efforts. States are already looking towards decarbonization goals. In New Jersey, Governor Murphy's Executive Order 28 directed the 2019 Energy Master Plan to provide a blueprint towards achieving 100% clean energy by 2050.[2] In Maryland the recently passed SB 516 which increased the state's RPS target to 50% by 2030 also requires an assessment of the costs and benefits of a 100% renewable energy by 2040 goal and the completion of a plan with recommendations for the achievement of that goal.

In the Aggressive Policy Case, the New Jersey, Pennsylvania, Maryland and Delaware targets all reflect an assumption of decarbonization by 2050, but rather than assuming targets of 100% by 2050, ICF has used 85% in acknowledgement of the feasibility constraints that exist in attaining a 100% RPS with status quo technology and transmission assumptions. All solar carve-out and offshore wind targets, where applicable, increase to higher levels than in the Moderate Policy Case by 2050. As in the Moderate Policy Case, Ohio and D.C. targets remain unchanged from the BAU.

The resulting REC prices from the Moderate and Aggressive Policy Cases offer a slight upside to the BAU Policy Case REC price forecast through 2030 but provide a more significant upside post 2030. Through 2030, the increases in the Moderate and Aggressive Policy Case Tier I requirements are more than offset by increases in solar and offshore wind carve-outs, as in the BAU scenario. The significant increase in 2050 targets puts upward pressure on REC prices as the more aggressive targets lead to greater incentive to bank allowances for use in later years. Exhibit 12 shows the REC price projections for each Case.

Exhibit 12: Scenario Case REC Prices (2019$/MWh)

$/REC	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
BAU	7.3	7.4	7.4	7.7	8.7	10.6	12.4	11.1	10.0	8.6	3.2	3.2	3.2	3.2	3.2
Moderate	7.3	7.4	7.6	8.0	9.0	10.9	12.7	11.3	10.2	8.7	3.2	9.8	6.3	4.9	6.3
Aggressive	7.3	7.4	7.6	8.0	9.0	10.9	12.7	11.3	10.2	8.7	3.2	10.2	7.7	9.1	7.5

[2] In June 2019 the Draft 2019 Energy Master Plan was released (https://nj.gov/emp/pdf/Draft%202019%20EMP%20Final.pdf)

Probability Weighted REC Price Projection

Exhibit 13 reflects the risk of policy uncertainty regarding existing PJM RPS programs. Each probability considers the likelihood of specific states within each Case taking action to change their RPS programs, and on what timeline they may act. In the resulting weighted REC price forecast shown in Exhibit 14, ICF weighted each Case together with the probabilities shown in Exhibit 13.

Exhibit 13: Scenario Case Probabilities (%)

Probabilities	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
BAU	90	80	75	70	65	55	45	35	25	15	5	0	0	0	0
Moderate	5	15	20	25	30	40	47	54	61	68	75	75	70	60	40
Aggressive	5	5	5	5	5	5	8	11	14	17	20	25	30	40	60

Exhibit 14: Virginia in RGGI Case PJM Tier I Weighted REC Price Forecast (2019$/MWh)

$/REC	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
Weighted	7.3	7.4	7.4	7.8	8.8	10.7	12.6	11.2	10.1	8.6	3.2	9.9	6.7	6.6	7.0

The BAU Policy Case has a high probability in 2020, but it quickly begins to decrease and by 2035 it reaches 0%. This is because of the high rate of change that RPS programs experience; it is highly unlikely that the PJM states will not again revise their RPS programs in the next couple years.

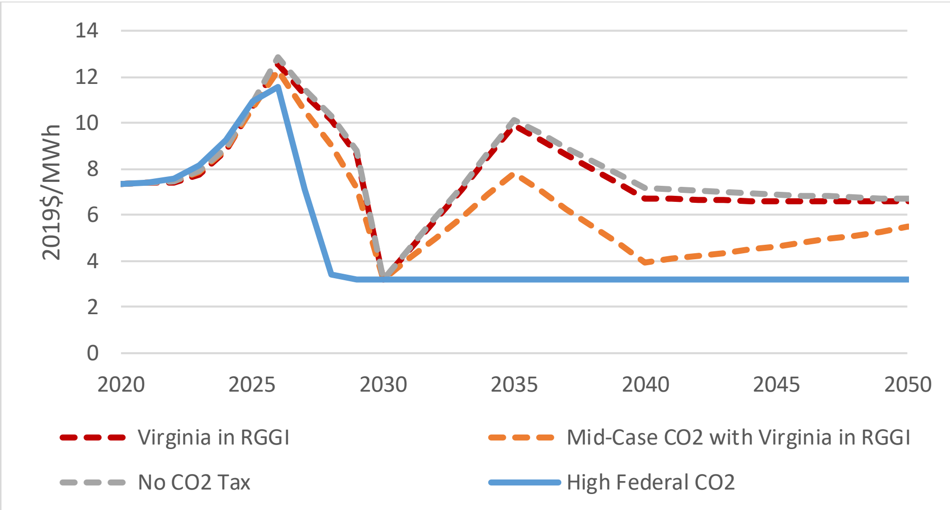
The Moderate Policy Case probability increases quickly, as the likelihood of such near-term changes is high. The probability of the Moderate Policy Case peaks at 75% for 2030-2035 before falling to 40% by 2060. The Moderate Policy Case targets do extend from 2030 to 2050 in all states (except Ohio), so there's a chance that states don't increase all the way to the Aggressive Policy Case 2050 targets.

The Aggressive Policy Case targets focus on the post-2030 period, with minor differences to the Moderate Policy Case prior to 2030. The Aggressive Policy Case is weighted at 5% until 2026, after which it increases to 20% by 2030. By 2060, the likelihood increases to 60%, as current political goals for decarbonization are expected to continue and only get stronger in the future. The offshore wind carve-outs in the Aggressive Policy Case for 2060 may end up being conservative in reality; however, given current costs and industry reliance on state mandates, ICF did not take an aggressive stance on offshore wind additions outside of current state mandates. As such, there's room for offshore wind to play a much large role in meeting long-term RPS targets than it does in this analysis, which would result in lower Tier I REC prices in the long-term, all else equal.

REC Price Projection Comparisons

Differences in REC prices between the cases, both with and without Virginia in RGGI and with various CO2 price assumptions, are largely driven by changes in market revenues due to the CO2 price specification. As shown below, the weighted REC prices from the cases with no assumed federal carbon regulation track closely. The Mid-Case CO2 with Virginia in RGGI and High Federal CO2 Case fall below the prior two cases. The High Federal CO2 Case is below all the other cases due to the higher energy revenues, leading to an earlier and sustained collapse in REC prices.

Exhibit 15: PJM Tier I Weighted REC Price Forecast Comparison (2019$/MWh)



Federal Tax Credit Extension Sensitivity

The Tax Credit Extension Case extends the PTC at 60% of its full value and the ITC at 30% indefinitely. This significantly reduces the cost to build renewables, resulting in a greater renewable capacity buildout and depressed REC prices. Exhibit 16 below shows the REC price forecast for the three RPS scenarios as well as the weighted price. REC prices immediately decline in each of the three RPS scenarios after the forwards period, reaching the floor price in 2028 in all RPS scenarios and remaining there until 2060. In each of these cases, onshore wind and solar are both economic 2028-2060 and do not need incremental revenue support to meet the states' RPS requirements.

Exhibit 16: ICF Tax Extension Case PJM Tier I Weighted REC Price Forecast (2019$/MWh)

$/REC	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
BAU	7.32	7.41	8.35	6.34	4.06	3.69	3.33	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20
Moderate	7.32	7.41	8.35	6.34	4.31	4.04	3.68	3.22	3.20	3.20	3.20	3.20	3.20	3.20	3.20
Aggressive	7.32	7.41	8.35	6.34	4.30	4.03	3.66	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20
Weighted	7.32	7.41	8.35	6.34	4.15	3.85	3.51	3.21	3.20	3.20	3.20	3.20	3.20	3.20	3.20

Voluntary REC Markets

Outside of the mandated RPS goals of individual states, a voluntary market for renewable supply exists. This market is driven by companies, government agencies, and private consumers who choose to procure renewable energy products for goodwill gained through environmental marketing value, or other purposes outside the RPS policy requirements. Developers with renewable energy projects outside of the eligibility criteria of a state RPS program may find an opportunity to generate additional revenue through the sale of RECs into the voluntary market.

Most voluntary market purchases are unbundled RECs (i.e. not inclusive of energy or capacity), and rely on certification programs that verify that the RECs were generated by an eligible facility and that the chain of REC custody is fully audited. Voluntary buyers are generally highly interested in where the REC was generated. For example, a buyer in Virginia may be more willing to purchase locally generated RECs then those from far away to maximize the benefit perceived by the local community and stakeholders.

Unlike RPS driven requirements, there is no enforcement of voluntary markets, and hence, the demand is considered a soft demand, motivated by internal drivers rather than external ones. While higher voluntary (Green-e) REC prices are exhibited in ERCOT and some WECC markets, the value of Green-e RECs tend to remain at a lower level on an average basis. Exhibit 17 shows ICF's Green-e REC price forecast.

Exhibit 17: Green-e REC Price Forecast (2019$/MWh)

$/REC	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
Green-e	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.9	1.0	1.0	1.0

Appendix 4R – Delivered Fuel Data for Plan B

Company Name: Virginia Electric and Power Company **Schedule 18**

FUEL DATA

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Delivered Fuel Price ($/mmBtu)(1)																			
a. Nuclear	0.70	0.67	0.61	0.61	0.60	0.63	0.70	0.70	0.70	0.69	0.70	0.70	0.72	0.73	0.74	0.74	0.75	0.76	0.77
b. Biomass	3.00	3.02	3.09	2.53	2.55	2.58	2.61	2.63	2.66	2.69	2.72	2.75	2.79	2.84	2.89	2.94	3.00	3.05	3.11
c. Coal	2.70	2.94	2.82	1.97	2.09	2.39	2.60	2.66	2.73	2.80	2.87	2.94	3.00	3.08	3.16	3.23	3.31	3.39	3.47
d. Heavy Fuel Oil	6.34	7.28	7.77	11.08	9.91	9.09	8.83	9.42	9.98	10.46	11.10	11.84	12.59	12.89	13.22	13.55	13.89	14.23	14.58
e. Light Fuel Oil(2)	11.73	10.91	14.90	14.90	14.28	13.87	14.31	15.16	15.97	16.69	17.61	18.68	19.75	20.78	21.60	22.26	22.83	23.34	23.83
f. Natural Gas	3.50	4.83	3.44	2.86	3.22	3.33	3.29	3.22	3.32	3.62	3.76	3.96	4.21	4.45	4.54	4.63	4.72	4.81	4.92
II. Primary Fuel Expenses (cents/kWh)(3)																			
a. Nuclear	0.72	0.69	0.63	0.63	0.63	0.66	0.72	0.73	0.73	0.72	0.73	0.73	0.75	0.75	0.76	0.77	0.78	0.79	0.80
b. Biomass	4.25	4.57	4.79	2.81	2.90	2.94	2.99	3.09	3.13	3.16	3.22	3.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00
c. Coal	2.88	3.02	3.13	1.94	2.05	2.35	2.56	2.63	2.69	2.76	2.83	2.90	2.96	3.04	3.11	3.19	3.27	3.35	3.43
d. Heavy Fuel Oil	7.60	6.15	0.00	10.97	10.07	9.18	8.23	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
e. Light Fuel Oil(2)	16.32	15.83	18.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
f. Natural Gas	2.64	3.34	2.41	1.73	1.87	2.06	2.08	1.98	2.09	2.27	2.36	2.48	2.64	2.78	2.88	2.95	2.94	2.98	3.08
g. NUG(4)	5.28	4.49	4.67	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
i. Economy Energy Purchases(5)	3.36	4.88	3.25	2.29	2.36	2.60	2.70	2.63	3.04	3.29	3.29	3.37	3.42	3.64	3.50	3.51	3.92	4.02	3.74
j. Capacity Purchases ($/kW-Year)	52.64	58.12	46.35	31.50	41.45	51.31	52.48	53.50	54.52	55.56	56.64	57.74	58.88	60.04	61.21	62.39	63.59	64.81	66.05

Notes: 1) Delivered fuel price for NAPP (12,900, 3.2% 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) Primary Fuel Expenses for Nuclear, Biomass, Coal, Heavy Fuel Oil and Natural Gas are based on North Anna 1, Altavista, Mount Storm 1, Possum Point 5, Possum Point 6, respectively

4) Average of NUGs fuel expenses.

5) Average cost of market energy purchases.

Appendix 5A – 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
Altavista	Altavista, VA	Base	Renewable	Feb-1992	51
Bath County 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,808
Bear Garden	Buckingham County, VA	Intermediate	Natural Gas-CC	May-2011	622
Brunswick	Brunswick County, VA	Intermediate	Natural Gas-CC	May-2016	1,376
Chesapeake CT 1, 4, 6	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	39
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	336
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	678
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	195
Clover 1	Clover, VA	Base	Coal	Oct-1995	220
Clover 2	Clover, VA	Base	Coal	Mar-1996	219
Colonial Trail West	Surry, VA	Intermittent	Renewable	Dec-2019	93
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	110
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	110
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	110
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109
Gravel Neck 1-2	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	85
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85
Greensville	Brunswick County, VA	Intermediate	Natural Gas-CC	Dec-2018	1,588
Hopewell	Hopewell, VA	Base	Renewable	Jul-1989	51
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160
Lowmoor CT 1-4	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48

Note: (1) Commercial operation date.

Appendix 5A 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
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	548
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	553
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	520
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	838
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1
Northern Neck CT 1-4	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47
Possum Point 5	Dumfries, VA	Peak	Heavy Fuel Oil	Jun-1975	623
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	573
Possum Point CT 1-6	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95
Rosemary	Roanoke Rapids, NC	Peak	Natural Gas-CC	Dec-1990	165
Scott Solar	Powhatan, VA	Intermittent	Renewable	Dec-2016	11
Solar Partnership Program	Distributed	Intermittent	Renewable	Jan-2012	5
Southampton	Franklin, VA	Base	Renewable	Mar-1992	51
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	838
Surry 2	Surry, VA	Base	Nuclear	May-1973	838
Virginia City Hybrid Energy Center	Virginia City, VA	Base	Coal	Jul-2012	610
Warren	Front Royal, VA	Intermediate	Natural Gas-CC	Dec-2014	1,370
Whitehouse Solar	Louisa, VA	Intermittent	Renewable	Dec-2016	12
Woodland Solar	Isle of Wight, VA	Intermittent	Renewable	Dec-2016	13
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	790
Subtotal - Base					7,185
Subtotal - Intermediate					8,263
Subtotal - Peak					4,220
Subtotal - Intermittent					134
Total					19,802

Note: (1) Commercial operation date.

Appendix 5B – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units(1)					
W. E. Partners II	NC	Biomass	300	3/15/2012	Auto renew
W. E. Partners 1	NC	Biomass	100	4/26/2013	Auto renew
Weyerhaeuser/Domtar	NC	Coal/Biomass	28,400(2)	7/27/1991	Auto renew
3620 Virginia Dare Trail N	NC	Solar	4	9/14/2009	Auto renew
Plymouth Solar	NC	Solar	5,000	10/4/2012	10/3/2027
Dogwood Solar	NC	Solar	20,000	12/9/2014	12/8/2029
HXOap Solar	NC	Solar	20,000	12/16/2014	12/15/2029
Bethel Price Solar	NC	Solar	5,000	12/9/2014	12/8/2029
Jakana Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Lewiston Solar	NC	Solar	5,000	12/18/2014	12/17/2029
Williamston Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Windsor Solar	NC	Solar	5,000	12/17/2014	12/16/2029
510 REPP One Solar	NC	Solar	1,250	3/11/2015	3/10/2030
Everetts Wildcat Solar	NC	Solar	5,000	3/11/2015	3/10/2030
SolNC5 Solar	NC	Solar	5,000	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Solar	14,000	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Solar	5,000	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Solar	5,000	11/1/2015	10/31/2030
Downs Farm Solar	NC	Solar	5,000	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Solar	5,000	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Solar	5,000	12/18/2015	12/17/2030
Green Farm Solar	NC	Solar	5,000	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Solar	20,000	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Solar	20,000	1/28/2016	1/27/2031
Bradley PVI- FAE IX	NC	Solar	5,000	2/4/2016	2/3/2031
Conetoe Solar	NC	Solar	5,000	2/5/2016	2/4/2031
SolNC3 Solar-Sugar Run Solar	NC	Solar	5,000	2/5/2016	2/4/2031
Gates Solar	NC	Solar	5,000	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Solar	5,000	2/12/2016	2/11/2031
Battleboro Farm Solar	NC	Solar	5,000	2/17/2016	2/16/2031
Winton Solar	NC	Solar	5,000	2/8/2016	2/7/2031
SolNC10 Solar	NC	Solar	5,000	1/13/2016	1/12/2031
Tarboro Solar	NC	Solar	5,000	12/31/2015	12/30/2030
Bethel Solar	NC	Solar	4,400	3/3/2016	3/2/2031
Garysburg Solar	NC	Solar	5,000	3/18/2016	3/17/2031
Woodland Solar	NC	Solar	5,000	4/7/2016	4/6/2031
Gaston Solar	NC	Solar	5,000	4/18/2016	4/17/2031
TWE Kelford Solar	NC	Solar	4,700	6/6/2016	6/5/2031
FAE XVIII - Meadows	NC	Solar	20,000	6/9/2016	6/8/2031
Seaboard Solar	NC	Solar	5,000	6/29/2016	6/28/2031
Simons Farm Solar	NC	Solar	5,000	7/13/2016	7/12/2031
Whitakers Farm Solar	NC	Solar	3,400	7/20/2016	7/19/2031
MC1 Solar	NC	Solar	5,000	8/19/2016	8/18/2031
Williamston West Farm Solar	NC	Solar	5,000	8/23/2016	8/22/2031
River Road Solar	NC	Solar	5,000	8/23/2016	8/22/2031
White Farm Solar	NC	Solar	5,000	8/26/2016	8/25/2031
Hardison Farm Solar	NC	Solar	5,000	9/9/2016	9/8/2031
Modlin Farm Solar	NC	Solar	5,000	9/14/2016	9/13/2031

Notes: (1) In operation as of April 1, 2020; generating facilities that have contracted directly with Virginia Electric and Power Company

(2) PPA is for excess energy only typically 4,000 – 14,000 kW.

(3) PPA is for excess energy only typically 3,500 kW.

Appendix 5B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Battleboro Solar	NC	Solar	5,000	10/7/2016	10/6/2031
Williamston Speight Solar	NC	Solar	15,000	11/23/2016	11/22/2031
Barnhill Road Solar	NC	Solar	3,100	11/30/2016	11/29/2031
Hemlock Solar	NC	Solar	5,000	12/5/2016	12/4/2031
Leggett Solar	NC	Solar	5,000	12/14/2016	12/13/2031
Schell Solar Farm	NC	Solar	5,000	12/22/2016	12/21/2031
FAE XXXV - Turkey Creek	NC	Solar	13,500	1/31/2017	1/30/2027
FAE XXII - Baker PVI	NC	Solar	5,000	1/30/2017	1/29/2032
FAE XXI -Benthall Bridge PVI	NC	Solar	5,000	1/30/2017	1/29/2032
Aulander Hwy 42 Solar	NC	Solar	5,000	12/30/2016	12/29/2031
Floyd Road Solar	NC	Solar	5,000	6/19/2017	6/18/2032
Flat Meeks- FAE II	NC	Solar	5,000	10/27/2017	10/26/2032
HXNAir Solar One	NC	Solar	5,000	12/21/2017	12/20/2032
Cork Oak Solar	NC	Solar	20,000	12/29/2017	12/28/2027
Sunflower Solar	NC	Solar	16,000	12/29/2017	12/28/2027
Davis Lane Solar	NC	Solar	5,000	12/31/2017	12/30/2032
FAE XIX- American Legion PVI	NC	Solar	15,840	1/2/2018	1/1/2033
FAE XXV-Vaughn's Creek	NC	Solar	20,000	1/2/2018	1/1/2033
TWE Ahoskie Solar Project	NC	Solar	5,000	1/12/2018	1/11/2033
Cottonwood Solar	NC	Solar	3,000	1/25/2018	1/24/2033
Shiloh Hwy 1108 Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Chowan Jehu Road Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Phelps 158 Solar Farm	NC	Solar	5,000	2/26/2018	2/25/2033
Sandy Solar	NC	Solar	5,000	5/30/2018	5/29/2033
Northern Cardinal Solar	NC	Solar	2,000	6/29/2018	6/28/2033
Carl Friedrich Gauss Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Sun Farm VI Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Sun Farm V Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Citizens Hertford	NC	Solar	16,200	6/6/2019	6/5/2029
Camden Dam Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Mill Pond Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Jamesville Road	NC	Solar	5,000	9/10/2018	9/9/2033
North 301	NC	Solar	20,000	12/18/2019	12/17/2029
Five Forks	NC	Solar	20,000	12/23/2019	12/22/2029
Whitehurst PVI Solar	NC	Solar	10,000	3/13/2020	3/12/2035
FAE XXXIII-Grandy	NC	Solar	20,000	3/13/2020	3/12/2030
MeadWestvaco (formerly Westvaco)	VA	Coal/Biomass	140,000	11/3/1982	8/25/2028
Smurfit-Stone Container	VA	Coal/Biomass	48,400(3)	3/21/1981	Auto renew
Brasfield Dam	VA	Hydro	2,800	10/12/1993	Auto renew
Columbia Mills	VA	Hydro	343	2/7/1985	Auto renew
Lakeview (Swift Creek) Dam	VA	Hydro	400	11/26/2008	Auto renew
Banister Dam	VA	Hydro	1,785	9/28/2008	Auto renew
Chapman Dam	VA	Hydro	300	10/17/1984	Auto renew
Burnshire Dam	VA	Hydro	100	7/11/2016	Auto renew
Cushaw Hydro	VA	Hydro	7,500	11/21/2018	11/20/2033
Suffolk Landfill	VA	Methane	3,000	11/4/1994	Auto renew
Alexandria/Arlington - Covanta	VA	MSW	21,000	1/29/1988	1/28/2023
Essex Solar Center	VA	Solar	20,000	12/14/2017	12/13/2037

Notes: (1) In operation as of April 1, 2020; generating facilities that have contracted directly with Virginia Electric and Power Company.
(2) PPA is for excess energy only typically 4,000 – 14,000 kW.
(3) PPA is for excess energy only typically 3,500 kW.

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Appendix 5C – Equivalent Availability Factor for Plan B

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Altavista	63	75	79	92	90	90	100	100	85	85	85	85	100	-	-	-	-	-	-
Bath County 1-6	90	82	87	91	91	89	89	92	91	91	91	91	91	91	91	91	91	91	91
Battery_Gen1				-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100
Battery_Gen2				-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100
Battery_Gen3				-	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100
Battery_Gen4				-	-	-	-	-	-	-	-	-	-	-	-	100	100	100	100
Battery_Gen5				-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Bear Garden	80	85	73	79	77	80	80	82	79	79	79	79	79	79	79	79	79	79	79
Brunswick	82	84	74	81	81	76	85	84	80	80	80	80	80	80	80	80	80	80	80
Chesapeake CT 1, 4, 6	99	94	85	90	90	89	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	65	57	47	77	87	84	100	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	59	47	51	73	79	84	100	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	84	69	78	71	92	80	92	85	87	87	87	87	87	87	87	87	87	87	87
Chesterfield 8	86	75	77	59	92	81	85	92	84	84	84	84	84	84	84	84	84	84	84
Clover 1	88	86	61	83	86	88	86	86	100	-	-	-	-	-	-	-	-	-	-
Clover 2	65	71	75	86	86	88	88	86	100	-	-	-	-	-	-	-	-	-	-
CVOW - Phase 1 (880MW)				-	-	-	-	-	-	35	37	40	39	39	39	40	39	39	39
CVOW - Phase 2 (880MW)				-	-	-	-	-	-	-	35	37	39	39	39	40	39	39	39
CVOW - Phase 3 (880MW)				-	-	-	-	-	-	-	35	37	39	39	39	40	39	39	39
CVOW (Pilot)				-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Darbytown 1	92	97	89	67	93	85	93	93	90	90	90	90	90	90	90	90	90	90	90
Darbytown 2	93	87	97	94	94	87	71	94	90	90	90	90	90	90	90	90	90	90	90
Darbytown 3	89	97	89	94	94	87	94	94	90	90	90	90	90	90	90	90	90	90	90
Darbytown 4	92	73	93	94	94	87	94	94	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 1	93	90	90	58	87	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 2	92	76	75	93	87	94	94	69	90	90	90	90	90	90	90	90	90	90	90
Elizabeth River 3	92	80	94	92	87	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Gaston Hydro	91	91	77	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Generic Brownfield CT				-	-	-	92	92	92	92	92	92	92	92	92	92	92	92	92
Generic Solar PV- (60MW)				-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Generic Solar PV PPA Post 2022				-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25
Generic Solar PV PPA Pre 2022				-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Generic Storage - Battery (Pilot) -14MW				-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Generic Storage - Battery (Pilot) -16MW	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Gordonsville 1	77	74	84	77	83	89	79	84	84	84	84	84	84	84	84	84	84	84	84
Gordonsville 2	52	82	83	70	75	84	89	86	85	85	85	85	85	85	85	85	85	85	85
Gravel Neck 1-2	100	95	93	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	90	100	95	87	91	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 4	87	90	95	87	94	91	94	94	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 5	91	96	95	87	94	94	94	94	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 6	91	98	97	87	94	91	94	94	90	90	90	90	90	90	90	90	90	90	90

Note: EAF for intermittent resources shown as a capacity factor.

Appendix 5C cont. – Equivalent Availability Factor for Plan B

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	(ACTUAL)			(PROJECTED)															
Greensville	-	96	73	80	81	79	80	78	79	79	79	79	79	79	79	79	79	79	79
Hopewell	78	83	83	43	88	88	100	100	82	82	82	82	100	-	-	-	-	-	-
Ladysmith 1	85	93	86	90	90	90	79	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 2	85	94	86	90	90	90	79	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 3	84	74	87	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 4	77	79	87	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 5	83	95	87	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Lowmoor CT 1-4	98	98	99	91	91	91	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	74	76	64	80	82	76	76	87	81	81	81	81	81	81	81	81	81	81	81
Mount Storm 2	81	66	60	70	76	86	86	81	81	81	81	81	81	81	81	81	81	81	81
Mount Storm 3	71	72	54	76	86	76	86	88	82	82	82	82	82	82	82	82	82	82	82
Mount Storm CT	96	79	98	90	90	89	-	-	-	-	-	-	-	-	-	-	-	-	-
New Pump Storage				-	-	-	-	-	-	-	-	-	-	70	70	70	70	70	70
North Anna 1	100	90	93	98	89	91	98	79	91	98	91	84	98	84	91	98	91	91	98
North Anna 2	90	99	88	89	98	91	77	98	91	91	98	91	84	98	84	91	91	98	91
North Anna Hydro	100	100	100	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Northern Neck CT 1-4	94	99	97	90	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	62	57	69	77	84	100	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	75	83	69	60	72	82	84	77	75	75	75	75	75	75	75	75	75	75	75
Possum Point CT 1-6	97	95	100	90	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	91	94	79	89	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 2	91	87	79	89	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 3	70	89	76	89	90	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 4	83	88	79	89	90	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Roanoke Rapids Hydro	92	90	72	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Rosemary	78	78	85	92	83	96	83	96	90	90	100	100	100	100	100	100	100	100	100
Scott Solar				24	24	24	24	24	24	24	24	23	23	23	23	23	23	23	23
Solar Partnership Program				14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Solar_DG				-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Southampton	68	84	83	92	92	90	100	100	84	84	84	84	100	-	-	-	-	-	-
Surry 1	99	87	89	98	91	91	98	84	84	98	84	91	98	74	91	100	100	100	100
Surry 2	92	89	100	87	91	98	91	84	98	82	84	98	74	91	98	98	100	100	100
US-3 Solar 1				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
US-3 Solar 2				-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
US-4 Solar				-	25	25	25	25	25	25	25	26	26	26	26	26	26	26	27
Virginia City Hybrid Energy Center	74	64	55	75	78	78	78	78	77	77	77	77	77	77	77	77	77	77	77
Warren	88	78	80	81	72	81	81	81	79	79	79	79	79	79	79	79	79	79	79
Water Strider				-	25	25	25	26	26	26	26	26	26	26	26	27	27	27	27
Westmoreland_PPA				-	24	25	25	25	25	25	25	25	25	26	26	26	26	26	26
Whitehouse Solar				25	25	24	24	24	24	24	24	24	24	23	23	23	23	23	23
Woodland Solar				25	25	25	25	25	24	24	24	24	24	24	24	24	24	23	23
Yorktown 3	78	74	71	74	81	81	81	100	-	-	-	-	-	-	-	-	-	-	-

Note: EAF for intermittent resources shown as a capacity factor.

Appendix 5D – Net Capacity Factor for Plan B

Company Name: Virginia Electric and Power Company **Schedule 9**

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Altavista	.	61.3	61.0	40.3	53.1	72.5	40.5	4.6	5.9	6.7	5.7	6.0	-	-	-	-	-	-	-
Bath County 1-6	14.2	15.5	12.2	9.6	10.7	10.2	10.1	10.6	9.9	9.8	9.0	8.4	7.3	6.3	7.2	6.6	6.7	6.8	7.5
Battery_Gen1				-	-	-	-	-	-	14.8	13.1	13.7	12.7	12.2	12.2	11.7	12.9	14.2	14.9
Battery_Gen2				-	-	-	-	-	-	-	13.1	13.4	12.6	12.1	12.4	11.9	13.3	14.7	14.6
Battery_Gen3				-	-	-	-	-	-	-	-	-	12.9	11.9	12.2	11.9	12.9	15.0	14.9
Battery_Gen4				-	-	-	-	-	-	-	-	-	-	-	-	11.9	12.6	14.3	15.1
Battery_Gen5				-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.9	15.1
Bear Garden	62.1	74.3	65.3	74.2	65.2	74.6	74.3	76.5	73.1	68.4	66.1	63.5	62.2	62.3	53.2	48.8	50.9	41.8	36.3
Brunswick	67.8	70.0	69.1	77.8	77.5	72.9	81.9	80.7	76.2	73.5	70.0	67.8	65.5	65.9	60.1	55.9	60.5	54.6	49.6
Chesapeake CT 1, 4, 6	0.0	0.7	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	43.4	24.1	10.4	12.9	12.8	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	31.3	22.5	10.6	9.2	7.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	89.7	74.4	84.3	65.5	82.2	71.8	80.6	70.0	70.1	62.4	57.1	53.9	49.3	51.8	44.1	39.0	45.3	36.6	31.1
Chesterfield 8	90.2	76.6	74.4	53.0	81.3	71.9	73.9	79.6	67.2	63.2	58.3	55.3	52.3	53.0	46.3	40.9	47.2	39.4	33.1
Clover 1	48.0	38.6	17.3	12.9	13.8	9.9	8.0	8.6	-	-	-	-	-	-	-	-	-	-	-
Clover 2	37.1	37.3	16.1	13.9	13.5	8.9	7.9	8.2	-	-	-	-	-	-	-	-	-	-	-
CVOW - Phase 1 (880MW)				-	-	-	-	-	-	35.3	37.4	39.5	39.4	39.4	39.4	39.5	39.4	39.4	39.4
CVOW - Phase 2 (880MW)				-	-	-	-	-	-	-	35.3	37.4	39.4	39.4	39.4	39.5	39.4	39.4	39.4
CVOW - Phase 3 (880MW)				-	-	-	-	-	-	-	35.3	37.4	39.4	39.4	39.4	39.5	39.4	39.4	39.4
CVOW (Pilot)				-	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8
Darbytown 1	1.9	2.2	2.0	2.7	2.9	2.2	1.7	1.7	1.5	1.3	1.1	1.0	0.9	0.7	0.8	0.6	0.5	0.5	0.3
Darbytown 2	1.8	2.5	2.2	3.5	2.9	2.2	1.1	1.7	1.5	1.3	1.1	1.0	0.9	0.8	0.8	0.6	0.6	0.5	0.3
Darbytown 3	2.7	3.5	1.6	3.5	2.9	2.2	1.9	1.7	1.5	1.3	1.1	1.0	0.9	0.8	0.8	0.6	0.6	0.5	0.4
Darbytown 4	8.7	3.3	2.6	3.5	2.9	2.2	1.7	1.7	1.5	1.3	1.1	1.0	0.9	0.8	0.8	0.6	0.6	0.5	0.3
Elizabeth River 1	3.3	9.1	4.0	1.9	1.6	2.1	2.3	2.2	2.4	2.2	1.3	1.3	0.8	0.3	0.2	0.3	0.2	0.1	0.1
Elizabeth River 2	3.5	8.1	4.6	2.6	1.6	2.0	2.3	2.1	2.4	2.1	1.3	1.2	0.6	0.3	0.2	0.3	0.2	0.1	0.1
Elizabeth River 3	3.2	9.3	1.7	2.6	1.6	2.1	2.3	2.2	2.4	2.1	1.3	1.3	0.7	0.3	0.2	0.3	0.2	0.1	0.1
Gaston Hydro	14.1	24.5	19.1	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Generic Brownfield CT				-	-	-	2.9	2.9	4.4	3.6	2.6	1.9	1.3	0.9	0.3	0.3	0.3	0.1	0.1
Generic Solar PV- (60MW)				-	-	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Generic Solar PV PPA Post 2022				-	-	-	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Generic Solar PV PPA Pre 2022				-	-	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Generic Storage - Battery (Pilot) -14MW				-	-	-	14.2	14.3	13.4	12.1	10.3	9.9	8.9	7.8	8.4	7.3	-	-	-
Generic Storage - Battery (Pilot) -16MW				-	14.8	14.3	14.2	14.3	13.4	12.1	10.3	9.9	8.9	7.8	-	-	-	-	-
Gordonsville 1	14.2	39.7	64.9	55.6	44.4	49.3	34.9	36.5	39.7	32.9	29.2	26.7	22.8	22.1	18.7	15.5	19.3	15.2	11.8
Gordonsville 2	9.6	49.2	61.2	48.1	42.9	48.2	40.1	38.2	38.1	32.6	28.0	26.6	22.5	21.6	18.4	15.4	18.9	15.0	11.5
Gravel Neck 1-2	0.1	0.1	0.0	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	3.6	4.8	4.2	3.9	2.9	2.9	2.9	3.3	4.3	3.1	2.5	2.2	1.7	1.4	0.6	0.3	0.3	0.3	0.2
Gravel Neck 4	0.8	1.5	0.3	4.0	3.0	3.0	3.0	3.3	4.3	3.1	2.5	2.3	1.8	1.4	0.7	0.4	0.7	0.6	0.3
Gravel Neck 5	3.3	2.9	4.6	3.9	3.0	3.0	3.0	3.4	4.4	3.1	2.5	2.2	1.8	1.4	0.6	0.4	0.3	0.5	0.3
Gravel Neck 6	0.6	3.1	1.5	4.0	3.0	3.0	3.0	3.3	4.3	3.1	2.5	2.3	1.8	1.4	0.6	0.4	0.7	0.5	0.3

Appendix 5D cont. – Net Capacity Factor for Plan B

Company Name: Virginia Electric and Power Company **Schedule 9**

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

(ACTUAL) (PROJECTED)

Unit Name	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Greensville	-	34.8	70.9	77.0	78.2	76.4	77.6	75.1	76.0	75.7	74.2	71.8	70.8	71.0	66.2	63.3	66.7	63.1	59.5
Hopewell	66.0	68.4	64.0	11.7	35.3	59.2	48.2	3.8	4.3	5.3	3.9	4.4	-	-	-	-	-	-	-
Ladysmith 1	9.4	11.3	11.0	9.7	7.0	7.8	8.3	8.7	8.6	6.8	6.0	5.7	5.3	4.9	3.8	3.4	3.2	3.6	1.9
Ladysmith 2	11.1	22.3	8.5	9.8	6.9	7.9	8.3	8.6	8.5	6.8	6.0	5.7	5.2	5.0	3.8	3.6	3.2	3.6	1.9
Ladysmith 3	5.7	9.0	11.7	10.0	7.4	7.9	8.6	8.9	8.7	7.0	6.3	5.9	5.4	5.2	3.9	3.5	3.4	3.9	2.0
Ladysmith 4	9.4	5.5	13.4	9.7	7.2	8.0	8.6	9.0	8.7	7.1	6.3	5.9	5.4	5.1	3.9	3.4	3.4	3.9	2.0
Ladysmith 5	6.5	3.6	3.3	9.8	7.2	8.2	8.6	8.9	8.7	7.0	6.3	6.0	5.5	5.2	3.9	3.5	3.4	3.9	2.0
Lowmoor CT 1-4	0.1	0.7	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	49.4	43.4	36.8	38.1	41.2	40.6	32.1	31.9	36.8	12.4	11.0	11.3	12.6	14.5	13.8	11.3	9.8	6.7	5.2
Mount Storm 2	58.0	32.2	34.6	38.0	41.3	45.4	38.0	34.3	39.3	13.0	11.8	12.2	13.9	15.5	15.5	12.1	10.8	7.5	6.0
Mount Storm 3	39.1	41.2	25.2	29.2	36.0	32.3	24.8	23.5	30.8	8.1	7.0	7.3	8.1	9.6	7.9	6.7	5.8	3.8	3.1
Mount Storm CT	0.0	0.2	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Pump Storage				-	-	-	-	-	-	-	-	-	-	8.4	8.3	7.9	8.0	8.5	8.7
North Anna 1	102.3	91.1	94.5	96.3	87.8	89.2	96.3	77.8	89.0	96.3	88.9	82.9	96.3	82.9	89.0	96.3	88.9	89.0	96.1
North Anna 2	92.3	101.9	90.4	87.5	96.4	89.2	75.7	96.4	88.9	89.1	96.4	88.9	82.9	96.4	82.9	89.1	88.9	96.2	88.5
North Anna Hydro	29.2	26.2	7.0	29.1	29.0	29.0	29.0	29.1	29.0	29.0	29.0	29.1	29.0	29.0	29.0	29.1	29.0	29.0	29.0
Northern Neck CT 1-4	0.2	0.6	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	0.9	0.8	0.5	6.0	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	59.1	71.2	56.3	57.0	63.3	76.5	77.8	71.3	66.9	62.4	60.2	57.1	54.8	53.4	48.0	44.9	49.2	43.3	36.5
Possum Point CT 1-6	0.1	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	9.9	19.5	6.5	4.7	2.6	3.3	3.7	5.2	5.7	4.9	3.9	3.1	2.7	1.9	1.8	1.1	1.1	0.8	0.8
Remington 2	9.8	16.0	3.8	4.6	2.7	3.3	3.6	5.1	5.6	4.9	3.9	3.1	2.6	1.9	1.9	1.1	1.1	0.8	0.8
Remington 3	10.0	18.8	7.1	5.6	3.0	4.0	4.4	5.4	6.0	5.2	4.2	3.5	2.9	2.0	2.0	1.1	1.2	0.8	0.9
Remington 4	8.6	17.7	4.9	5.6	3.2	3.7	4.6	6.0	6.6	5.2	4.2	3.3	2.7	2.0	1.9	1.4	1.2	0.8	0.8
Roanoke Rapids Hydro	25.7	45.2	36.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5
Rosemary	9.8	2.0	0.2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-
Scott Solar	20.6	13.7	13.9	24.4	24.3	24.2	24.1	23.9	23.8	23.7	23.6	23.5	23.4	23.3	23.1	23.0	22.9	22.8	22.7
Solar Partnership Program	-			13.7	13.7	13.7	13.7	13.7	13.7	13.8	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Solar_DG				-	-	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Southampton	62.5	70.2	59.4	20.6	35.2	60.1	55.8	3.6	4.1	5.3	3.8	4.5	-	-	-	-	-	-	-
Surry 1	102.4	89.4	90.5	95.9	89.2	88.7	95.9	82.9	82.2	95.9	82.8	88.4	95.9	72.5	88.4	-	-	-	-
Surry 2	94.2	90.7	102.6	85.7	88.7	95.9	88.7	82.3	95.9	80.2	82.2	95.9	72.5	88.4	95.9	95.9	-	-	-
US-3 Solar 1	-			25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
US-3 Solar 2	-			-	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
US-4 Solar	-			-	24.7	24.8	24.9	25.0	25.2	25.3	25.4	25.5	25.7	25.8	26.0	26.1	26.2	26.4	26.5
Virginia City Hybrid Energy Center	62.4	55.4	22.2	5.7	6.8	7.4	7.4	8.0	10.8	7.9	6.7	7.1	7.8	9.4	8.3	6.7	6.2	4.2	3.2
Warren	75.7	69.2	73.1	69.4	53.0	67.5	73.4	75.4	73.6	66.1	62.3	58.5	56.0	56.7	51.9	49.2	52.2	42.8	36.2
Water Strider				-	25.2	25.3	25.4	25.6	25.7	25.8	26.0	26.1	26.2	26.3	26.4	26.6	26.7	26.8	26.9
Westmoreland_PPA				-	24.5	24.6	24.7	24.8	25.0	25.1	25.2	25.3	25.5	25.6	25.7	25.9	26.0	26.1	26.2
Whitehouse Solar	19.9	16.2	23.9	24.7	24.5	24.4	24.3	24.2	24.1	23.9	23.8	23.7	23.6	23.5	23.3	23.2	23.1	23.0	22.9
Woodland Solar	17.8	19.1	21.6	25.1	25.0	24.8	24.7	24.6	24.5	24.4	24.2	24.1	24.0	23.9	23.8	23.6	23.5	23.4	23.3
Yorktown 3	1.1	3.8	0.8	3.0	3.0	3.0	3.0	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 5E – Heat Rates for Plan B

Company Name: Virginia Electric and Power Company **Schedule 10**

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Altavista	15.16	15.82	15.18	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32	12.32							
Bath County 1-6																			
Battery_Gen1																			
Battery_Gen2																			
Battery_Gen3																			
Battery_Gen4																			
Battery_Gen5																			
Bear Garden	6.54	7.11	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17	7.17
Brunswick	6.96	6.94	6.86	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
Chesapeake CT 1, 4, 6	16.90	15.27	15.87	18.54	18.54														
Chesterfield 5	10.23	10.30	10.15	9.86	9.86	9.86													
Chesterfield 6	10.25	10.33	10.09	10.14	10.14	10.14													
Chesterfield 7	7.53	7.46	7.23	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33
Chesterfield 8	7.38	7.37	7.32	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25
Clover 1	10.31	10.41	10.61	9.84	9.84	9.84	9.84	9.84											
Clover 2	10.21	10.02	10.34	9.84	9.84	9.84	9.84	9.84											
CVOW - Phase 1 (880MW)																			
CVOW - Phase 2 (880MW)																			
CVOW - Phase 3 (880MW)																			
CVOW (Pilot)																			
Darbytown 1	12.45	12.21	12.33	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04
Darbytown 2	12.35	12.16	12.20	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03
Darbytown 3	12.36	12.21	11.39	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02
Darbytown 4	12.43	12.27	12.61	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03
Elizabeth River 1	12.06	12.36	12.38	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14
Elizabeth River 2	12.24	12.34	12.61	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Elizabeth River 3	12.11	12.38	12.54	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Gaston Hydro																			
Generic Brownfield CT							9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52
Generic Solar PV- (60MW)																			
Generic Solar PV PPA Post 2022																			
Generic Solar PV PPA Pre 2022																			
Generic Storage - Battery (Pilot) -14MW																			
Generic Storage - Battery (Pilot) -16MW																			
Gordonsville 1	8.60	8.30	8.13	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19	8.19
Gordonsville 2	8.51	8.20	8.32	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18
Gravel Neck 1-2	17.86	18.14	20.16																
Gravel Neck 3	12.61	12.84	12.96	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35
Gravel Neck 4	13.02	12.79	13.05	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34
Gravel Neck 5	13.09	12.97	13.66	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35
Gravel Neck 6	12.79	12.79	13.13	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34

Appendix 5E cont. – Heat Rates for Plan B

Company Name: Virginia Electric and Power Company **Schedule 10**

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

Unit Name	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	(ACTUAL)			(PROJECTED)															
Greensville	-	4.26	6.55	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66
Hopewell	15.98	15.74	16.35	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10							
Ladysmith 1	9.96	10.30	9.84	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 2	9.70	9.75	9.55	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 3	9.99	9.95	9.75	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 4	9.84	10.13	9.60	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 5	9.98	10.17	9.70	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Lowmoor CT 1-4	16.86	15.44	16.75	16.76	16.76														
Mount Storm 1	10.16	10.15	10.42	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86
Mount Storm 2	10.05	10.04	10.38	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78
Mount Storm 3	10.56	10.79	10.60	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19
Mount Storm CT	16.03	14.18	14.63	20.36	20.36														
New Pump Storage																			
North Anna 1	10.36	10.36	10.33	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40
North Anna 2	10.39	10.34	10.34	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42
North Anna Hydro																			
Northern Neck CT 1-4	16.87	15.44	17.47	16.83	16.83														
Possum Point 5	11.87	11.69	12.43	9.93	9.93														
Possum Point 6	7.18	7.08	7.11	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43
Possum Point CT 1-6	17.32	15.28	17.03	16.83	16.83														
Remington 1	10.01	9.92	9.82	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Remington 2	10.10	10.08	9.98	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Remington 3	10.03	9.93	9.85	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Remington 4	9.99	10.00	9.89	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Roanoke Rapids Hydro			-																
Rosemary	9.48	10.07	10.82	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76
Scott Solar																			
Solar Partnership Program																			
Solar_DG																			
Southampton	15.70	16.45	16.63	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70							
Surry 1	10.21	10.24	10.26	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Surry 2	10.24	10.33	10.26	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
US-3 Solar 1																			
US-3 Solar 2																			
US-4 Solar																			
Virginia City Hybrid Energy Center	10.02	10.01	11.67	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39
Warren	6.88	6.85	6.87	6.95	6.96	6.96	6.96	6.95	6.96	6.96	6.96	6.95	6.96	6.96	6.96	6.95	6.96	6.96	6.96
Water Strider																			
Westmoreland_PPA																			
Whitehouse Solar																			
Woodland Solar																			
Yorktown 3	10.86	10.17	9.97	10.15	10.15	10.15	10.15												

Appendix 5F – Existing Capacity for Plan B

Company Name: Virginia Electric and Power Company **Schedule 7**

CAPACITY DATA

	(ACTUAL)			(PROJECTED)															
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Firm Capacity (MW)(1)																			
a. Nuclear	3,357	3,357	3,357	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. Biomass(3)	183	183	183	205	211	214	214	214	214	214	214	214	61	61	61	61	61	61	61
c. Coal	4,400	4,400	3,654	3,632	3,626	3,623	2,609	2,609	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170	2,170
d. Heavy Fuel Oil	1,572	1,572	1,559	1,413	1,413	790	790	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	596	596	584	234	206	206	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	543	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	4,948	5,756	6,293	6,304	6,304	6,304	6,304	6,304	6,304	6,304	6,139	6,139	6,139	6,139	6,139	6,139	6,139	6,139	6,139
h. Natural Gas-Turbine	2,053	2,053	2,051	2,408	2,408	2,408	2,882	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367
i. Hydro-Conventional	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
j. Pumped Storage & Battery	1,808	1,808	1,808	1,808	1,815	1,815	1,820	1,820	1,820	1,924	2,054	2,054	2,184	2,484	2,478	2,608	2,602	2,732	2,732
k. Renewable	6	6	6	73	147	367	571	810	1,012	1,504	2,215	2,449	2,770	3,125	3,360	3,594	3,827	4,825	5,055
l. Total Company Firm Capacity	19,782	20,047	19,810	19,741	19,793	19,391	18,855	18,788	18,552	19,148	19,824	20,058	20,356	21,011	21,240	21,604	21,831	22,959	23,189
m. Other (NUG)(4)	238	-	-	-	36	137	260	401	523	719	909	1,089	1,319	1,456	1,573	1,759	1,875	2,060	2,175
n. Total	20,020	20,047	19,810	19,741	19,829	19,528	19,114	19,190	19,075	19,867	20,733	21,147	21,675	22,467	22,813	23,363	23,706	25,019	25,364
II. Firm Capacity Mix (%)(2)																			
a. Nuclear	16.8%	16.7%	16.9%	17.0%	16.9%	17.1%	17.5%	17.4%	17.6%	16.9%	16.2%	15.8%	15.4%	14.9%	14.7%	14.3%	14.1%	13.4%	13.2%
b. Biomass(3)	0.9%	0.9%	0.9%	1.0%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.0%	1.0%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%
c. Coal	22.0%	21.9%	18.4%	18.4%	18.3%	18.6%	13.6%	13.6%	11.4%	10.9%	10.5%	10.3%	10.0%	9.7%	9.5%	9.3%	9.2%	8.7%	8.6%
d. Heavy Fuel Oil	7.9%	7.8%	7.9%	7.2%	7.1%	4.0%	4.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Light Fuel Oil	3.0%	3.0%	2.9%	1.2%	1.0%	1.1%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	2.7%	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%
g. Natural Gas-Combined Cycle	24.7%	28.7%	31.8%	31.9%	31.8%	32.3%	33.0%	32.9%	33.0%	31.7%	29.6%	29.0%	28.3%	27.3%	26.9%	26.3%	25.9%	24.5%	24.2%
h. Natural Gas-Turbine	10.3%	10.2%	10.4%	12.2%	12.1%	12.3%	15.1%	17.5%	17.7%	16.9%	16.2%	15.9%	15.5%	15.0%	14.8%	14.4%	14.2%	13.5%	13.3%
i. Hydro-Conventional	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.7%	1.6%	1.7%	1.6%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.3%	1.3%	1.2%
j. Pumped Storage & Battery	9.0%	9.0%	9.1%	9.2%	9.2%	9.3%	9.5%	9.5%	9.5%	9.7%	9.9%	9.7%	10.1%	11.1%	10.9%	11.2%	11.0%	10.9%	10.8%
k. Renewable	0.0%	0.0%	0.0%	0.4%	0.7%	1.9%	3.0%	4.2%	5.3%	7.6%	10.7%	11.6%	12.8%	13.9%	14.7%	15.4%	16.1%	19.3%	19.9%
l. Total Company Firm Capacity	98.8%	100.0%	100.0%	100.0%	99.8%	99.3%	98.6%	97.9%	97.3%	96.4%	95.6%	94.9%	93.9%	93.5%	93.1%	92.5%	92.1%	91.8%	91.4%
m. Other (NUG)(4)	1.2%	0.0%	0.0%	0.0%	0.2%	0.7%	1.4%	2.1%	2.7%	3.6%	4.4%	5.1%	6.1%	6.5%	6.9%	7.5%	7.9%	8.2%	8.6%
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%

Notes: 1) Net dependable annual firm capability during peak season.
2) Each item in Section I as a percent of line n (Total).
3) Includes current estimates for renewable capacity by VCHEC.
4) Includes 35% Solar DG and 35% energy storage battery.

Appendix 5G – Energy Generation by Type for Plan B (GWh)

Company Name: Virginia Electric and Power Company **Schedule 2**

GENERATION

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. System Output (GWh)																			
a. Nuclear	28,683	27,361	27,720	27,928	27,601	27,673	27,199	25,925	27,144	27,556	26,691	27,227	26,498	25,923	27,163	28,612	27,722	28,286	28,242
b. Biomass(1)	1,163	1,196	1,008	355	590	897	686	97	123	121	97	106	43	51	45	37	34	23	18
c. Coal	15,376	12,302	7,177	6,925	7,509	7,027	5,328	5,136	5,775	2,035	1,795	1,875	2,084	2,405	2,241	1,815	1,605	1,090	862
d. Heavy Fuel Oil	141	313	88	633	383	208	86	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	131	313	35	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	163	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	26,832	28,500	37,219	40,996	39,496	41,421	43,507	43,048	41,601	39,378	37,654	36,156	34,861	34,999	31,773	29,829	31,925	28,193	25,197
h. Natural Gas-Turbine	1,246	1,888	1,168	1,445	1,012	1,113	1,311	1,576	1,760	1,432	1,158	1,007	843	702	518	425	411	404	240
i. Hydro-Conventional	876	1,577	1,311	612	610	610	610	612	610	610	610	612	610	610	610	612	610	610	610
j. Pumped Storage & Battery	2,240	2,453	1,934	1,523	1,718	1,634	1,633	1,720	1,603	1,926	2,130	2,057	2,202	2,202	2,342	2,552	2,665	3,274	3,446
k. Renewable	102	80	90	444	915	2,294	3,616	5,128	6,423	10,541	17,255	19,258	21,579	23,831	25,355	26,963	28,381	38,709	40,201
l. Total Generation	76,953	76,094	77,750	80,862	79,833	82,877	83,976	83,241	85,039	83,599	87,390	88,298	88,721	90,723	90,048	90,845	93,352	100,588	98,815
m. Purchased Power (NUGs)	4,611	4,289	2,616	-	219	850	1,647	2,544	3,326	4,208	4,988	6,145	7,164	8,027	8,786	9,569	10,294	11,042	11,786
n. Purchased Power (Battery Storage)	-	-	-	-	-	-	-	-	-	181	362	373	547	518	528	693	753	1,061	1,096
o. Purchased Power (Market / PJM)	10,488	14,537	13,552	4,773	7,127	6,347	7,089	9,315	6,747	9,275	7,304	6,949	7,593	7,208	7,998	8,467	7,525	4,272	6,256
p. Total Payback Energy(2)				8	9	12	16	19	22	24	25	24	23	23	23	23	23	23	24
q. Less Pumping Energy	(3,014)	(3,043)	(2,801)	(1,904)	(2,147)	(2,023)	(2,052)	(2,154)	(1,994)	(2,583)	(3,036)	(2,962)	(3,341)	(3,283)	(3,444)	(3,900)	(4,108)	(5,204)	(5,457)
r. Less Other Sales(3)	(1,680)	(225)	(561)	(2,222)	(1,653)	(2,219)	(2,268)	(2,607)	(2,155)	(3,126)	(4,808)	(5,559)	(6,636)	(8,354)	(8,236)	(8,922)	(10,377)	(13,329)	(12,952)
s. Total System Firm Energy Req.	87,359	91,652	90,556	81,510	83,379	85,832	88,392	90,340	90,962	91,554	92,200	93,244	94,047	94,838	95,680	96,752	97,440	98,431	99,544
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

Notes: (1) Includes current estimates for renewable energy generation by VCHEC.
(2) Payback energy is accounted for in Total Generation.
(3) Includes all sales or delivery transactions with other electric utilities (*e.g.*, firm or economy sales).

Appendix 5H – Energy Generation by Type for Plan B (%)

Company Name: Virginia Electric and Power Company | **Schedule 3**

GENERATION

	(ACTUAL)				(PROJECTED)														
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
III. System Output Mix (%)																			
a. Nuclear	32.8%	29.9%	30.6%	34.3%	33.1%	32.2%	30.8%	28.7%	29.8%	30.1%	28.9%	29.2%	28.2%	27.3%	28.4%	29.6%	28.5%	28.7%	28.4%
b. Biomass[1]	1.3%	1.3%	1.1%	0.4%	0.7%	1.0%	0.8%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
c. Coal	17.6%	13.4%	7.9%	8.5%	9.0%	8.2%	6.0%	5.7%	6.3%	2.2%	1.9%	2.0%	2.2%	2.5%	2.3%	1.9%	1.6%	1.1%	0.9%
d. Heavy Fuel Oil	0.2%	0.3%	0.1%	0.8%	0.5%	0.2%	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%
e. Light Fuel Oil	0.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
f. Natural Gas-Boiler	0.2%	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%	0.0%
g. Natural Gas-Combined Cycle	30.7%	31.1%	41.1%	50.3%	47.4%	48.3%	49.2%	47.7%	45.7%	43.0%	40.8%	38.8%	37.1%	36.9%	33.2%	30.8%	32.8%	28.6%	25.3%
h. Natural Gas-Turbine	1.4%	2.1%	1.3%	1.8%	1.2%	1.3%	1.5%	1.7%	1.9%	1.6%	1.3%	1.1%	0.9%	0.7%	0.5%	0.4%	0.4%	0.4%	0.2%
i. Hydro-Conventional	1.0%	1.7%	1.4%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
j. Pumped Storage & Battery	2.6%	2.7%	2.1%	1.9%	2.1%	1.9%	1.8%	1.9%	1.8%	2.1%	2.3%	2.2%	2.3%	2.3%	2.4%	2.6%	2.7%	3.3%	3.5%
k. Renewable	0.1%	0.1%	0.1%	0.5%	1.1%	2.7%	4.1%	5.7%	7.1%	11.5%	18.7%	20.7%	22.9%	25.1%	26.5%	27.9%	29.1%	39.3%	40.4%
l. Total Generation	88.1%	83.0%	85.9%	99.2%	95.7%	96.6%	95.0%	92.1%	93.5%	91.3%	94.8%	94.7%	94.3%	95.7%	94.1%	93.9%	95.8%	102.2%	99.3%
m. Purchased Power (NUGs)	5.3%	4.7%	2.9%	0.0%	0.3%	1.0%	1.9%	2.8%	3.7%	4.6%	5.4%	6.6%	7.6%	8.5%	9.2%	9.9%	10.6%	11.2%	11.8%
n. Purchased Power (Battery Storage)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.4%	0.4%	0.6%	0.5%	0.6%	0.7%	0.8%	1.1%	1.1%
o. Purchased Power (Market / PJM)	12.0%	15.9%	15.0%	5.9%	8.5%	7.4%	8.0%	10.3%	7.4%	10.1%	7.9%	7.5%	8.1%	7.6%	8.4%	8.8%	7.7%	4.3%	6.3%
p. Total Payback Energy[2]	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%
q. Less Pumping Energy	-3.5%	-3.3%	-3.1%	-2.3%	-2.6%	-2.4%	-2.3%	-2.4%	-2.2%	-2.8%	-3.3%	-3.2%	-3.6%	-3.5%	-3.6%	-4.0%	-4.2%	-5.3%	-5.5%
r. Less Other Sales[3]	-1.9%	-0.2%	-0.6%	-2.7%	-2.0%	-2.6%	-2.6%	-2.9%	-2.4%	-3.4%	-5.2%	-6.0%	-7.1%	-8.8%	-8.6%	-9.2%	-10.6%	-13.5%	-13.0%
s. Total System Firm Energy Req.	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	57.7%	56.6%	59.0%	60.6%	61.3%	61.0%	61.3%	61.8%	61.6%	61.9%	62.4%	61.8%	61.9%	62.5%	62.1%	62.2%	61.9%	62.0%	62.1%

Notes: (1) Includes current estimates for renewable energy generation by VCHEC.
(2) Payback energy is accounted for in Total Generation.
(3) Includes all sales or delivery transactions with other electric utilities (*e.g.*, firm or economy sales).

Appendix 5I – Solar and Wind Generating Facilities Since July 1, 2018

Project Name	Status	Nameplate (MWac)	In Service Date	Type	Cost Recovery Mechanism
Hollyfield	Operational	17	2018	Company-build	Ring-Fence
Montross	Operational	20	2018	Company-build	Ring-Fence
Puller	Operational	15	2018	Company-build	Ring-Fence
Colonial Trail West	Operational	142	2019	Company-build	RAC
Gloucester	Operational	20	2019	Company-build	Ring-Fence
Spring Grove 1	In Construction	98	2020 (proj)	Company-build	RAC
Sadler	In Construction	100	2020 (proj)	Company-build	RAC
Westmoreland	In Construction	20	2020 (proj)	PPA	Fuel / Base
Rives Road *	In Construction	20	2020 (proj)	PPA	Fuel / Base
Pamplin *	In Construction	16	2020 (proj)	PPA	Fuel / Base
Hickory *	In Construction	32	2020 (proj)	PPA	Fuel / Base
Water Strider	In Construction	80	2020 (proj)	PPA	Fuel / Base
Coastal VA Offshore Wind (CVOW)	In Construction	12	2020 (proj)	Company-build	Base Rate
Grasshopper	In Construction	80	2020 (proj)	Company-build	Ring-Fence
Belcher	In Construction	88	2020 (proj)	Company-build	Ring-Fence
Rochambeau	In Construction	20	2021 (proj)	Company-build	Ring-Fence
Fort Powhatan	In Construction	150	2021 (proj)	Company-build	Ring-Fence
Bedford	In Construction	70	2021 (proj)	Company-build	Ring-Fence
Rocky Forge	In Construction	77	2021 (proj)	Company-build	Ring-Fence
Maplewood	In Construction	120	2022 (proj)	Company-build	Ring-Fence

* Variable pricing based on PJM energy and capacity prices.

Appendix 5J - 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
Gravel Neck 1	**Surry, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2020**	**28**	**38**
Gravel Neck GT1					12	
Gravel Neck GT2					16	
Possum Point 5(2)	**Dumfries, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2021**	**623**	**623**
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**15**	**20**
Chesapeake GT1					15	
Chesapeake CT 2	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**24**	**33**
Chesapeake GT4					12	
Chesapeake GT6					12	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**11**	**15**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**47**	**63**
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Possum Point CT	**Dumfries, VA**	**Steam-Cycle**	**Light Fuel Oil**	**2022**	**72**	**106**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	
Yorktown 3(2)	**Yorktown, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2023**	**790**	**792**
Chesterfield 5(2)	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**336**	**342**
Chesterfield 6(2)	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**678**	**690**
Clover 1(2)	**Clover, VA**	**Steam-Cycle**	**Coal**	**2025**	**220**	**222**
Clover 2(2)	**Clover, VA**	**Steam-Cycle**	**Coal**	**2025**	**219**	**219**
Rosemary(2)	**Roanoke Rapids, NC**	**Combine Cycle**	**Fuel Oil**	**2027**	**165**	**165**
Altavista(3)	**Altavista, VA**	**Steam-Cycle**	**Biomass**	**2028**	**51**	**51**
Hopewell(3)	**Hopewell, VA**	**Steam-Cycle**	**Biomass**	**2028**	**51**	**51**
Southampton(3)	**Franklin, VA**	**Steam-Cycle**	**Biomass**	**2028**	**51**	**51**

Notes: (1) Reflects retirement assumptions used for planning purposes, not firm Company commitments.
(2) These units are shown as planned retirements in all Alternative Plans.
(3) These units are shown as planned retirements in Alternative Plans B, C, and D only.

Appendix 5K – 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	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	(ACTUAL)				(PROJECTED)														
Altavista	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 4, 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Colonial Trail West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Greensville																			
Hopewell	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3																			
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	(163)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scott Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City Hybrid Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Whitehouse Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Woodland Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: Peak net dependable capability as of this filing. Incremental uprates shown as positive and decremental derates shown as negative.

Appendix 5L – Environmental Regulations

Constituent		Key Regulation	Final Rule	Compliance Date	Baseline Means of Compliance
AIR	Hg/HAPS	Mercury & Air Toxics Standards (1) (MATS)	12/16/2011	4/16/2017	All affected units compliant
	SO_2	CSAPR (2)	2011	2015/2017	Allowances (In-Sys.; Trading)
		SO_2 NAAQS (75 ppb, 1-hr avg)	6/2/2010	2018	Maintain current % sulfur oil level (3)
	NOx	2008 Ozone Standard (75 ppb)	May 2012	2019	DEQ requiring installation/operation of SNCR by 6/1/2019 to meet RACT or permanent retirement of unit by 6/1/2021 with operational limitations (no SNCR or NOx limit) in the interim. (4) Mutual agreement executed in June 2019 to retire unit by June 2021.
		2015 Ozone Standard (70 ppb)	10/1/2015	2021	Compliance with RACT (as described above)
		CSAPR (5)	2011	2015/2017	Allowances (In-Sys.; Trading)
	CO_2	NSR Permitting for GHGS	5/2010	2011	GHG BACT
		EGU NSPS (New) (6) (Subpart TTTT) Proposed revision	10/23/2015 12/20/2018	Retro to 1/8/2014 Retro to 12/20/2018	Build Gas CC or Install CCS Proposed revision: Build Gas CC or super-critical coal
		EGU NSPS (Modified and Reconstructed) (6) Proposed revision (Subpart TTTT)	10/23/2015 12/20/2018	10/23/2015 12/20/2018	Will need to evaluate on a project-by-project basis.
		Affordable Clean Energy (ACE) (replacement to CPP)	2019	2024/2025	To be determined by state plans. States to establish unit-specific emission performance standards based on identification of best system of emission reductions (BSER) based on unit heat rate improvement potential per EPA-established BSER guidelines.
		Virginia Carbon Regulations or RGGI (7)(20)	2019	2020 with glidepath to 2030	DEQ reproposed and has finalized with starting cap of 28 million tons. Cap reduced about 3%/year through 2030 (19.6 short tons) . Link to regional trading program via use of consignment auction with revenue returned to generators. If VA joins RGGI in future, auction proceeds go back to state (not generators) Compliance with renewables, new gas, possible unit retitrements and allowance purchases (if applicable).
		Federal CO_2 Program (Alternative Federal Legislation)	Uncertain	2026	Expected Price for CO_2
		Exectuive Order 43 (30% of VA gen from RE resources, 100% carbon-free by 2050)	9/16/2019	Plan due 7/1/2020 (19)	The Director of Department of Mines, Minerals and Energy (DMME), in consultation with the Secretary of Commerce and Trade, the Secretary of Natural Resources, and the Director of the Department of Environmental Quality (DEQ), shall develop a plan of action to produce thirty percent of Virginia's electricity from renewable energy sources by 2030 and one hundred percent of Virginia's electricity from carbon-free sources by 2050.
		Virginia Energy Plan; Commonwealth Energy Policy	7/1/2020	2020 - 2045	Sets a goal for VA to reach net zero emissions by 2045 and additionally states: that by 2040 Virginia will have a net zero carbon energy economy for all sectors, including electricity, transportation, building and industrial sectors. Developing energy resources necessary to produce 30 percent of VA's electricity from renewable energy sources by 2030 and 100 percent from VA's electricity carbon-free sources by 2040.
		Virginia Clean Economy Act	7/1/2020	2020 - 2045	VCEA establishes a mandatory portolio standard in VA. There are mandates for significant developments of renewable energy and energy storage resources, as well as retirement of existing carbon-emitting resources. Includes mandatory retirement of certain fossil-generating units: Chesterfield Units 5 & 6 and Yorktown 3 by 2024. Biomass facilities (Altavista, Hopewell, Southampton) by 2028) and shutting down all remaining fossil generating units by 2045. Allows petition for relief from these provisions if electric reliability or security is at risk

Appendix 5L cont. – Environmental Regulations

Constituent		Key Regulation	Final Rule	Compliance Date	Baseline Means of Compliance
WASTE	ASH	CCR's	4/17/2015	4/2018; 2020+	Close landfill & pond due to station closure. Pond and landfill to be excavated and recycled off site. (8)
				6/2018; 2020+	Close all three coal ash ponds by excavating material and placing into new landfill at or adjacent to plant. (8)
				4/2018; 2020+	All five ponds to be closed. A/B/C and E excavated to D. New landfill to be developed for ash in pond D. Continuning to evaluate onsite landfill or offsite recycling. (8)
				6/2019; 2020+	Fly &/or Bottom Ash - Wet to Dry Conversion to include construction and operation of new landfill; Lower and Upper Pond Closure through excavation and hauling to landfill or off site for recycling; construct new treatment ponds. (8)
				2020	Landfill closure (due to coal unit retirements)
				10/2018	Pond retrofit.
				10/2018	Pond retrofit and/or rebuilding.
				TBD	Monitor groundwater and corrective actions, if needed.
WATER	Water 316b	316(b) Impingement & Entrainment (9) (10)	5/19/2014	2016 (16)	316(b) Studies to Determine Compliance Needs and Submit Design & Source Water Body Data
				2019 (11)	
				2020	
				2021	
				2023 (12)	
				2023 (13)	VSDs; Screens; Fish Returns
				2025 (13)	
				2025 (13)	
				2023	Possible Low Capacity Exemption
	Water ELG	Effluent Limitation Guidelines (14)	9/30/2015	12/2023	FGD Water Treatment Facilities
				12/31/2023 (15)	Bottom Ash - Closed Loop Wet System
WIILDLIFE	Threatened & Endangered	Atlantic Sturgeon Endangered Species Listing	2/6/2012	2019/2020	Seeking ITP which may contain potential mitigation measures to address impingement and entrainment of Atlantic Sturgeon and impacts to critical habitat. (18)
		Atlantic Sturgeon Critical Habitat Listing	2017	2019-2023 (17)	Thermal discharge studies at CH and SU to determine compliance needs during NPDES permit reissuance.

Appendix 5L cont. – Environmental Regulations

Notes: Compliance assumed January 1 unless otherwise noted.

1) CEC 1-4 retired in 2014. YT 1-2, CH 3-4, MK 1-2 retired in 2019. On 12/28/2018, EPA proposed revisions to MATS Supplemental Finding but proposing to keep MATS in place. MATS went to OMB on 10/4, expecting final rule to be issued first half of 2020.

2) SO_2 allowances decreased by 50% in 2017. Retired units retain CSAPR allowances for 4 years. System is expected to have sufficient SO_2 allowances.

3) SO_2 NAAQS modeling submitted to VDEQ in 11/2016. Modeling shows compliance with the NAAQS. EPA has approved and issued notice indicating NAAQS attainment 8/2017. In March 2019, EPA published final rule retaining 75 ppb 1-hr SO_2 NAAQS. No additional impacts expected.

4) VDEQ issued SOP on 1/31/2019.

5) Final revisions to CSAPR reduced ozone season NOx allowances by ~22% beginning in 2017. Projected to have sufficient allowances even if limits imposed on use of banked Phase I allowances (~ 3.5:1). Retired units retain CSAPR allowances for 4 years. System is expected to have sufficient annual NO_x allowances.

6) 2015 rule under EPA review for possible repeal or replacement rule. EPA published proposed revisions on December 20, 2018.

7) In May 2019, VDEQ issued final rule establishing a cap-and-trade program that allows for linkage to an existing regional trading program (such as RGGI) and includes about a 30% reduction from 2020 levels by 2030 and other allowance pool reduction mechanisms. In 2020, legislation passed the Virginia General Assembly related to RGGI.

8) As a result of the 2019 SB1355 legislation, ash in ponds must be excavated and disposed of in the landfill or taken off site for recycling. Exact timing of start of work at each site TBD.

9) Rule would not apply to Mt. Storm under the assumption that the plant's man-made lake does not qualify as a "water of the U.S."

10) 316(b) studies will be due with discharge permit applications beginning in mid-2018. Installation of 316(b) technology requirements will be based on compliance schedules put into discharge permits.

11) 316(b) information due with permit application by March 2019. VDEQ has concurred with CCRS status for impingement but will grant only limited waivers to other requirements.

12) Assumes permit is issued in 2019 with 316(b) with submittal due 270 days before permit expires.

13) Assumes permit issued with a 4-year compliance schedule. Permit issuance dates: North Anna - Dec 2019, Surry - March 2021, CH - September 2021, PP 3 & 4 - April 2023.

14) Rule does not apply to simple-cycle CTs or biomass units.

15) Assumes June 2023 applicability date included in next permit cycle based on timetable of current reconsideration of ELG rule.

16) 316(b) studies and reports completed and submitted to agency. Permits administratively continued and waiting for BTA determination.

17) Compliance dates are determined during NPDES permit reissuance process and are expected to be as follows for each facility: SU-2021, CH-2021.

(18) ITP permit addendum to be filed fall 2019. Expect permit in fall 2020.

(19) The Director of DMME shall report monthly to the Secretary of Commerce and Trade on the progress of these efforts and shall submit the final plan to the Governor by July 1, 2020. Commonwealth shall procure at least 30% of the electricity under the statewide electric contract with Dominion Energy Virginia from renewable energy resources by 2022.

(20) HB 981 and SB 1027 authorizes Virginia to join Regional Greenhouse Gas Initiative model.

Appendix 5M – Tabular Results of Busbar

	Capacity Factor (%)										
$/kW-Year	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
CC - 3X1	$ 170	$ 202	$ 234	$ 266	$ 298	$ 330	$ 362	$ 394	$ 426	$ 459	$ 491
CC - 2X1	$ 185	$ 217	$ 250	$ 283	$ 316	$ 348	$ 381	$ 414	$ 447	$ 479	$ 512
CC - 1X1	$ 216	$ 251	$ 285	$ 320	$ 354	$ 389	$ 423	$ 457	$ 492	$ 526	$ 561
CT	$ 64	$ 121	$ 178	$ 235	$ 291	$ 348	$ 405	$ 462	$ 519	$ 576	$ 633
CT (Aero)	$ 126	$ 174	$ 221	$ 269	$ 316	$ 364	$ 411	$ 459	$ 506	$ 554	$ 601
Large Nuclear	$ 1,021	$ 1,031	$ 1,042	$ 1,052	$ 1,063	$ 1,074	$ 1,084	$ 1,095	$ 1,105	$ 1,116	$ 1,126
Nuclear SMR	$ 644	$ 654	$ 664	$ 674	$ 685	$ 695	$ 705	$ 715	$ 725	$ 735	$ 746
Biomass	$ 928	$ 979	$ 1,030	$ 1,082	$ 1,133	$ 1,184	$ 1,235	$ 1,286	$ 1,337	$ 1,388	$ 1,440
Fuel Cell	$ 1,256	$ 1,285	$ 1,315	$ 1,344	$ 1,373	$ 1,403	$ 1,432	$ 1,461	$ 1,491	$ 1,520	$ 1,549
SCPC w/ CCS	$ 1,028	$ 1,109	$ 1,190	$ 1,271	$ 1,352	$ 1,433	$ 1,514	$ 1,595	$ 1,676	$ 1,757	$ 1,838
Solar & CT (Aero)	$ 248	$ 284	$ 321	$ 357	$ 394	$ 430	$ 467	$ 503	$ 539	$ 576	$ 612
Solar (1)				$ 104							
Wind - Onshore (2)					$ 255						
Wind - Offshore (3)					$ 342						
Battery Generic (30 MW) (4)			$ 475								
Pump Storage (300 MW) (4)			$ 841								

(1) Solar has a capacity factor of 25%.
(2) Onshore Wind has a capacity factor of 40%.
(3) Offshore Wind has a capacity factor of 42%.
(4) Batteries and Pump Storage have a capacity factor of 15%.

Appendix 5N – Busbar Assumptions

Nominal $	Heat Rate	Variable Cost (1)	Fixed Cost (2)	Book Life	2020 Real $ (3)
	MMBtu/MWh	$/MWh	$/kW-Year	Years	$/kW
CC - 3X1	6.55	$36.57	$170.21	36	$908
CC - 2X1	6.59	$37.37	$184.69	36	$1,102
CC - 1X1	6.63	$39.36	$216.12	36	$1,492
CT	9.67	$64.94	$63.86	36	$562
CT (Aero)	9.32	$54.25	$126.13	36	$1,107
Large Nuclear	10.50	$12.09	$1,020.53	60	$9,352
Nuclear SMR	10.10	$11.64	$643.75	60	$5,478
Biomass	13.00	$58.37	$928.22	40	$6,694
Fuel Cell	8.54	$33.52	$1,255.81	15	$5,879
SCPC w/ CCS	11.44	$92.55	$1,027.60	55	$9,081
Solar & CT (Aero)	9.32	$41.60	$247.90	35 (Solar) / 36 (CT)	$2,670
Solar	-	-$8.99	$127.36	35	$1,363
Wind - Onshore	-	-$8.89	$286.30	25	$1,926
Wind - Offshore	-	-$8.89	$372.85	25	$2,952
Battery Generic (30 MW)	-	$36.51	$410.69	10	$2,224
Pump Storage (300 MW)	-	$47.66	$757.12	50	$7,541

(1) Variable cost for Biomass, Solar, Solar & Aero CT, Onshore Wind, and Offshore Wind includes value for RECs.

(2) Fixed costs include investment tax credits and gas firm transmission expenses.

(3) Values in this column represent overnight installed cost.

Appendix 5O – Renewable Resources for Plan B

Company Name: Virginia Electric and Power Company **Schedule 11**

RENEWABLE RESOURCE GENERATION (GWh)

							(ACTUAL)				(PROJECTED)														
Resource Type[1]	**Unit Name**	**State**	**C.O.D.[2]**	**Build / Purchase / Convert[3]**	**Life/ Duration[4]**	**Size MW[5]**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Hydro																									
	Gaston Hydro	NC	Feb-63	Build	60	220	271	472	368	321	320	320	320	321	320	320	320	321	320	320	320	321	320	320	320
	North Anna Hydro	VA	Dec-87	Build	60	1	3	2	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Roanoke Rapids Hydro	NC	Sep-55	Build	60	95	211	376	303	288	287	287	287	288	287	287	287	288	287	287	287	288	287	287	287
Sub-total: NC						315	482	848	671	609	607	607	607	609	607	607	607	609	607	607	607	609	607	607	607
Sub-total: VA						1	3	2	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Sub-total: Hydro						316	484	850	672	612	610	610	610	612	610	610	610	612	610	610	610	612	610	610	610
Solar																									
	Solar Partnership Program	VA	2013-2017	Build	20	7	10	4	4	9	9	9	9	9	9	9	9	9	9	9	9	9	9	8	8
	Existing NC Solar NUGs	NC					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Existing VA Solar NUGs	VA	2020-2021	Purchase	20		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Scott Solar	VA	Dec-2016	Build	35	17	31	21	21	37	37	37	37	36	36	36	36	36	35	35	35	35	35	35	34
	Whitehouse Solar	VA	Dec-2016	Build	35	19	28	32	32	43	43	43	43	42	42	42	42	42	41	41	41	41	40	40	40
	Woodland Solar	VA	Dec-2016	Build	35	20	33	33	33	42	42	42	41	41	41	41	41	41	40	40	40	40	39	39	39
	US-3 Solar 1	VA	2020	Build	35	142	-	-	6	313	310	309	307	306	304	303	301	300	298	297	295	294	292	291	289
	US-3 Solar 2	VA	2021	Build	35	98	-	-	-	-	214	214	212	212	210	209	208	207	206	205	204	203	202	201	200
	US-4 Solar	VA	2021	Build	36	100	-	-	-	-	216	215	215	216	215	215	215	216	215	215	215	216	215	215	215
	Water Strider	VA	2021	Purchase	35	80	-	-	-	-	176	176	176	176	176	176	176	176	176	176	175	176	175	175	175
	Westmoreland_PPA	VA	2021	Purchase	35	20	-	-	-	-	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
	Generic Solar PV_PPA	VA	2021-2035	Purchase	35	5,545	-	-	-	-	-	631	1,428	2,325	3,107	3,989	4,769	5,926	6,946	7,808	8,568	9,351	10,076	10,824	11,568
	Generic Solar PV	VA	2021-2035	Build	35	10,375	-	-	-	-	-	1,382	2,708	4,221	5,522	7,009	8,307	9,807	11,863	14,118	15,645	17,213	18,677	20,180	21,676
Sub-total: NC						0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total: VA						16,423	103	90	96	444	1,090	3,100	5,219	7,629	9,705	12,072	14,146	16,802	19,873	22,987	25,271	27,620	29,804	32,053	34,288
Sub-total: Solar						16,423	103	90	96	444	1,090	3,100	5,219	7,629	9,705	12,072	14,146	16,802	19,873	22,987	25,271	27,620	29,804	32,053	34,288
Wind																									
	CVOW (Pilot)	VA	Jan-21	Build	20	12	-	-	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
	Generic Wind		2021-2035	Build	20	5,112	-	-	-	-	-	-	-	-	-	2,633	8,053	8,557	8,827	8,827	8,827	8,868	8,827	17,655	17,655
Sub-total: NC						0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total: VA						5,124	-	-	-	-	44	44	44	44	44	2,676	8,097	8,601	8,871	8,871	8,871	8,912	8,871	17,698	17,698
Sub-total: Wind						5124	-	-	-	-	44	44	44	44	44	2,676	8,097	8,601	8,871	8,871	8,871	8,912	8,871	17,698	17,698
Total Renewables: NC						315	482	848	671	609	607	607	607	609	607	607	607	609	607	607	607	609	607	607	607
Total Renewables: VA						21,548	105	92	97	447	1,136	3,146	5,266	7,675	9,752	14,751	22,245	25,405	28,746	31,860	34,144	36,535	38,677	49,753	51,989
Total Renewables						21,863	587	940	768	1,056	1,743	3,754	5,873	8,284	10,359	15,358	22,852	26,015	29,353	32,468	34,752	37,144	39,285	50,361	52,597

Notes: (1) Per definition in 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 hydro, nameplate for solar and wind.

Appendix 5P – Potential Supply-Side Resources for Plan B

Company Name: ______________________ **Schedule 15b**

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Annual Firm	MW Nameplate
Solar 2022	Intermittent	Solar	2022	319	1,000
Battery Pilot	Storage		2023	6	14
Solar 2023	Intermittent	Solar	2023	330	960
Generic CT	Peak	Natural Gas	2023	485	485
Solar 2024	Intermittent	Solar	2024	381	1,180
Generic CT	Peak	Natural Gas	2024	458	458
Solar 2025	Intermittent	Solar	2025	330	960
Generic Battery	Storage		2026	160	400
Solar 2026	Intermittent	Solar	2026	381	1,180
CVOW - Phase 1	Intermittent	Wind	2026	256	852
Generic Battery	Storage		2027	200	500
Solar 2027	Intermittent	Solar	2027	330	960
CVOW - Phase 2-3	Intermittent	Wind	2027	511	1,704
Solar 2028	Intermittent	Solar	2028	422	1,300
Generic Battery	Storage		2029	200	500
Solar 2029	Intermittent	Solar	2029	495	1,440
Pump Storage	Storage		2029	300	300
Solar 2030	Intermittent	Solar	2030	505	1,540
Solar 2031	Intermittent	Solar	2031	372	1,080
Generic Battery	Storage		2032	200	500
Solar 2032	Intermittent	Solar	2032	372	1,080
Solar 2033	Intermittent	Solar	2033	372	1,080
Generic Battery	Storage		2034	200	500
Solar 2034	Intermittent	Solar	2034	372	1,080
Generic Offshore Wind	Intermittent	Wind	2034	767	2,556
Solar 2035	Intermittent	Solar	2035	372	1,080

Note: (1) Estimated commercial operation date.

Appendix 5Q – Summer Capacity Position for Plan B

Company Name: Virginia Electric and Power Company **Schedule 16**

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)				(PROJECTED)														
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Existing Capacity																			
Conventional	17,620	17,173	17,681	17,544	17,516	16,893	15,662	14,872	14,434	14,434	14,269	14,269	14,116	14,116	14,116	14,116	14,116	14,116	14,116
Renewable NC	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Renewable VA	58	58	58	74	74	73	73	73	73	72	72	72	72	71	71	71	71	70	70
Renewable	373	373	373	389	389	388	388	388	388	387	387	387	387	386	386	386	386	385	385
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	1,809	1,809	1,809	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
Storage	1,809	1,809	1,809	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
Total Existing Capacity	19,802	19,355	19,863	19,741	19,713	19,090	17,859	17,068	16,630	16,629	16,464	16,464	16,310	16,310	16,310	16,310	16,309	16,309	16,309
Generation Under Construction																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	74	74	73	73	73	72	72	72	71	71	70	70	70	69	69
Renewable	-	-	-	-	74	74	73	73	73	72	72	72	71	71	70	70	70	69	69
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-
Storage	-	-	-	-	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-
Total Planned Construction Capacity	-	-	-	-	80	80	80	79	79	79	78	78	78	77	70	70	70	69	69
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Development Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	485	970	970	970	970	970	970	970	970	970	970	970	970
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	-	221	426	665	868	1,360	2,072	2,307	2,628	2,984	3,220	3,454	3,688	4,686	4,917
Renewable	-	-	-	-	-	221	426	665	868	1,360	2,072	2,307	2,628	2,984	3,220	3,454	3,688	4,686	4,917
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	6	6	6	110	240	240	370	670	670	800	794	924	924
Storage	-	-	-	-	-	-	6	6	6	110	240	240	370	670	670	800	794	924	924
Total Potential New Capacity	-	-	-	-	-	221	916	1,641	1,843	2,440	3,282	3,516	3,968	4,624	4,859	5,224	5,452	6,580	6,811
Other (NUG)																			
Conventional	238	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	36	137	260	401	523	663	783	963	1,123	1,260	1,377	1,493	1,609	1,724	1,839
Renewable	-	-	-	-	36	137	260	401	523	663	783	963	1,123	1,260	1,377	1,493	1,609	1,724	1,839
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	56	126	126	196	196	196	266	266	336	336
Storage	-	-	-	-	-	-	-	-	-	56	126	126	196	196	196	266	266	336	336
Total Other (NUG) Capacity	238	-	-	-	36	137	260	401	523	719	909	1,089	1,319	1,456	1,573	1,759	1,875	2,060	2,175
Unforced Availability	-	-																	
Net Generation Capacity	20,040	19,355	19,863	19,741	19,829	19,528	19,114	19,190	19,075	19,867	20,733	21,147	21,675	22,467	22,813	23,363	23,706	25,019	25,364
Existing DSM Reductions																			
Demand Response	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Conservation/Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions(1)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Approved DSM Reductions																			
Demand Response(3)	69	58	55	63	63	64	64	65	65	65	65	66	66	66	66	66	66	66	66
Conservation/Efficiency(2)(3)	109	122	135	129	125	127	136	134	122	113	105	102	101	99	97	95	93	92	93
Total Approved DSM Reductions	178	180	190	191	188	191	201	199	188	179	171	167	167	165	163	160	159	158	158
Proposed DSM Reductions																			
Demand Response(3)	-	-	-	7	27	47	63	77	83	84	85	86	87	88	89	89	90	91	92
Conservation/Efficiency(2)	-	-	-	16	26	45	66	88	114	124	124	124	124	128	129	129	129	129	133
Total Proposed DSM Reductions	-	-	-	23	53	92	129	165	197	208	209	210	211	216	217	218	219	219	224
Unidentified DSM Reductions																			
Demand Response(3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency(2)	-	-	-	-	39	87	143	209	276	335	447	408	388	409	422	474	377	358	340
Total Proposed DSM Reductions	-	-	-	-	39	87	143	209	276	335	447	408	388	409	422	474	377	358	340
Total Demand-Side Reductions(1)	180	182	192	216	282	372	475	575	663	724	829	787	768	792	804	854	757	738	725
Net Generation & Demand-side	20,220	19,537	20,055	19,957	20,110	19,900	19,589	19,765	19,738	20,590	21,562	21,934	22,442	23,259	23,616	24,217	24,462	25,757	26,089
Capacity Requirement or PJM Capacity Obligation	19,769	20,548	20,251	20,022	20,218	19,800	20,150	20,396	20,327	20,599	20,596	20,927	21,050	21,219	21,219	21,472	21,818	21,963	22,114
Net Utility Capacity Position	452	(1,010)	(196)	(65)	(107)	99	(560)	(632)	(589)	(8)	965	1,007	1,392	2,040	2,398	2,745	2,645	3,794	3,975

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

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

(3) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

Appendix 5R – Capacity Position for Plan B

Company Name: Virginia Electric and Power Company **Schedule 4**

POWER SUPPLY DATA

		(ACTUAL)									(PROJECTED)								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
I. Capability (MW)																			
1. Summer																			
a. Firm Capacity Capacity(1)	19,802	19,355	19,863	19,741	19,793	19,391	18,855	18,788	18,552	19,148	19,824	20,058	20,356	21,011	21,240	21,604	21,831	22,959	23,189
b. Positive Interchange Commitments(2)	238	-	-	-	36	137	260	401	523	719	909	1,089	1,319	1,456	1,573	1,759	1,875	2,060	2,175
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
e. Demand Response - Approved(5)	69	58	55	63	63	64	64	65	65	65	65	66	66	66	66	66	66	66	66
f. Demand Response - Future(5)	-	-	-	7	27	47	63	77	83	84	85	86	87	88	89	89	90	91	92
g. Total Net Summer Capability(4)	20,109	19,413	19,918	19,809	19,917	19,637	19,240	19,330	19,221	20,014	20,881	21,297	21,825	22,618	22,965	23,516	23,860	25,174	25,520
2. Winter																			
a. Firm Capacity Capacity(1)	19,802	19,355	19,863	20,824	20,796	20,176	19,366	19,099	18,660	19,022	19,500	19,502	19,482	19,785	19,781	19,913	19,909	20,808	20,810
b. Positive Interchange Commitments(2)	238	-	-	-	0	1	2	3	5	62	133	134	206	207	208	279	280	351	352
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response(5)	6	6	6	16	37	58	76	92	100	102	103	104	105	106	107	108	109	110	111
e. Demand Response-Existing(3)	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
f. Total Net Winter Capability(4)	20,046	19,361	19,869	20,840	20,833	20,235	19,444	19,194	18,765	19,186	19,736	19,741	19,793	20,098	20,096	20,300	20,298	21,269	21,272

Notes: (1) Net seasonal capability.
(2) Does not include firm commitments from existing NUGs and estimated solar NUGs.
(3) Included in the winter capacity forecast.
(4) Does not include behind-the-meter generation MW.
(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity. Values reflective of free-ridership.

Appendix 5S – Construction Forecast for Plan B

Company Name: Virginia Electric and Power Company **Schedule 17**

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
I. New Traditional Generating Facilities																
a. Construction Expenditures (non-AFUDC)	319,804	326,223	518,290	644,848	436,991	312,115	385,020	381,492	249,784	248,810	216,379	59,406	90	-	-	-
b. AFUDC	674	2,036	3,816	5,129	5,953	7,532	9,001	10,617	11,948	12,999	13,979	6,116	6,241	-	-	-
c. Annual Total	320,478	328,259	522,106	649,976	442,944	319,647	394,021	392,109	261,732	261,809	230,358	65,522	6,331	-	-	-
d. Cumulative Total	320,478	648,736	1,170,843	1,820,819	2,263,763	2,583,411	2,977,432	3,369,541	3,631,273	3,893,083	4,123,441	4,188,962	4,195,293	4,195,293	4,195,293	4,195,293
II. New Renewable Generating Facilities																
a. Construction Expenditures (non-AFUDC)	1,373,964	986,242	1,510,731	1,751,487	2,968,887	3,522,621	2,886,428	2,173,190	1,776,645	1,485,727	1,977,360	1,721,729	3,653,218	4,534,938	1,852,148	-
b. AFUDC	3,619	6,815	8,220	10,995	16,772	17,150	14,149	9,080	11,811	11,693	11,878	14,142	20,266	32,226	5,469	-
c. Annual Total	1,377,583	993,057	1,518,951	1,762,483	2,985,659	3,539,771	2,900,577	2,182,269	1,788,457	1,497,421	1,989,238	1,735,870	3,673,485	4,567,164	1,857,617	-
d. Cumulative Total	1,377,583	2,370,640	3,889,592	5,652,074	8,637,733	12,177,505	15,078,081	17,260,351	19,048,807	20,546,228	22,535,466	24,271,336	27,944,821	32,511,985	34,369,601	34,369,601
III. New Storage Facilities																
a. Construction Expenditures (non-AFUDC)	80,059	31,873	48,798	40,065	773,117	1,082,325	1,076,455	569,975	1,251,422	147,334	56,572	851,006	-	882,437	-	732,024
b. AFUDC	169	265	435	491	2,206	6,810	8,975	8,287	13,041	11,677	-	2,760	-	2,862	-	2,374
c. Annual Total	80,227	32,138	49,234	40,556	775,323	1,089,135	1,085,430	578,261	1,264,463	159,011	56,572	853,765	-	885,299	-	734,398
d. Cumulative Total	80,227	112,365	161,599	202,156	977,478	2,066,613	3,152,043	3,730,304	4,994,767	5,153,778	5,210,350	6,064,115	6,064,115	6,949,414	6,949,414	7,683,812
IV. Other Facilities																
a. Transmission	921	885	885	723	751	751	751	751	751	751	751	751	751	751	751	751
b. Distribution	1,134	1,250	1,408	1,350	1,248	1,129	1,121	1,118	1,115	831	831	831	831	831	831	831
c. Energy Conservation & DR	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Other																
e. AFUDC	44	56	50	45	47	47	47	47	47	47	47	47	47	47	47	47
f. Annual Total	2,116	2,191	2,344	2,117	2,046	1,926	1,919	1,915	1,913	1,629	1,629	1,629	1,629	1,629	1,629	1,629
g. Cumulative Total	2,116	4,307	6,650	8,768	10,814	12,740	14,659	16,574	18,486	20,115	21,744	23,372	25,001	26,630	28,258	29,887
V. Total Construction Expenditures																
a. Annual	1,780,404	1,355,645	2,092,635	2,455,133	4,205,972	4,950,479	4,381,947	3,154,555	3,316,564	1,919,869	2,277,797	2,656,786	3,681,444	5,454,092	1,859,246	736,027
b. Cumulative	1,780,404	3,136,049	5,228,684	7,683,817	11,889,789	16,840,268	21,222,215	24,376,770	27,693,334	29,613,203	31,891,000	34,547,786	38,229,230	43,683,322	45,542,567	46,278,594
VI. % of Funds for Total Construction Provided from External Financing	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

Appendix 6A – Description of Active DSM Programs

Air Conditioner Cycling Program

Branded Name:	Smart Cooling Rewards
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Peak-Shaving
NC Program Type:	Peak-Shaving
VA Duration:	2010 – 2045
NC Duration:	2011 – 2045

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:

The Company uses business reply cards, online enrollment, and call center services.

Non-Residential Distributed Generation Program

Branded Name:	Distributed Generation
State:	Virginia
Target Class:	Non-Residential
VA Program Type:	Demand-Side Management
VA Duration:	2012 – 2045

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 at anytime for up to a total of 120 hours per year. The Company will supervise and implement the Non-Residential Distributed Generation Program through the third-party implementation contractor. Participating customers will receive an incentive in exchange for their agreement to reduce electrical load on the Company's system when called upon to do so by the Company. The incentive is based upon the amount of load curtailment delivered during control events. 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 is handled by the Company's implementation vendor.

Appendix 6A cont. – Description of Active DSM Programs

Income and Age Qualifying Home Improvement Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2015 – 2045
NC Duration:	2016 – 2045

Program Description:
This Program provides income and age-qualifying residential customers with energy assessments and direct install measures at no cost to the customer.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

Small Business Improvement Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2016 – 2045
NC Duration:	2017 – 2045

Program Description:
This Program provides eligible small businesses an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for the installation of specific energy efficiency measures. Participating small businesses are required to meet certain connected load requirements.

Program Marketing:
The Company uses a number of marketing activities to promote its 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 utilizes the contractor network to market the programs to customers as well.

Appendix 6A cont. – Description of Active DSM Programs

Non-Residential Prescriptive Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2017 – 2045
NC Duration:	2018 – 2045

Program Description:
This Program provides an incentive to eligible non-residential customers not otherwise eligible or who choose not to participate in the Company's Small Business Improvement Program. The Program offers incentives for the installation of energy efficiency measures such as Refrigerator Evaporator Fans (Reach-in and Walk-in Coolers and Freezers), Commercial ENERGY STAR Appliances, Commercial Refrigeration, Commercial ENERGY STAR Ice Maker, Advanced Power Strip, Cooler/Freezer Strip Curtain, HVAC Tune-Up, Vending Machine Controls, Kitchen Fan Variable Speed Drives and Commercial Duct Testing and Sealing.

Program Marketing:
The Company uses a number of marketing activities to promote its 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 utilizes the contractor network to market the programs to customers as well.

Residential Appliance Recycling Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:
This Program provides incentives to eligible residential customers to recycle specific types of qualifying freezers and refrigerators that are of specific of age and size. Appliance pick-up and proper recycling services are included.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Appendix 6A cont. – Description of Active DSM Programs

Residential Efficient Products Marketplace Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:

This Program provides eligible residential customers an incentive to purchase specific energy efficient appliances with a rebate through an online marketplace and through participating retail stores. The program offers rebates for the purchase of specific energy efficient appliances, including lighting efficiency upgrades such as A-line bulbs (prior to 2020), reflectors, decoratives, globes, retrofit kit and fixtures, as well as other appliances such as freezers, refrigerators, clothes washers, dehumidifiers, air purifiers, clothes dryers, and dishwashers.

Program Marketing:

The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Home Energy Assessment Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:

This Program provides qualifying residential customers with an incentive to install a variety of energy saving measures following completion of a walk-through home energy assessment. The energy saving measures include replacement of existing light bulbs with LED bulbs, heat pump tune-up, duct insulation/sealing, fan motors upgrades, installation of efficient faucet aerators and showerheads, water heater turndown, replacement of electric domestic hot water with heat pump water heater, heat pump upgrades (ducted and ductless), and water heater and pipe insulation.

Program Marketing:

The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Appendix 6A cont. – Description of Active DSM Programs

Non-Residential Lighting Systems & Controls Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

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 LED based bulbs and lighting control systems.

Program Marketing:

The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Heating and Cooling Efficiency Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:

This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing high efficiency heating and cooling system equipment to more efficient HVAC technologies that can produce verifiable savings.

Program Marketing:

The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Appendix 6A cont. – Description of Active DSM Programs

Non-Residential Window Film Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

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

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Small Manufacturing Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvements, consisting of primarily compressed air systems measures for small manufacturing facilities.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Appendix 6A cont. – Description of Active DSM Programs

Non-Residential Office Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvements, consisting of recommissioning measures at smaller office facilities.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Residential Customer Engagement Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Re-Proposed
NC Duration:	Future

Program Description:

This Program provides educational insights into the customer's energy consumption via a Home Energy Report (on-line and/or paper version). The Home Energy report is intended to provide periodic suggestions on how to save on energy based upon analysis of the customer's energy usage. Customers can opt-out of participating in the program at any time.

Appendix 6A cont. – Description of Active DSM Programs

Residential Smart Thermostat Program (DR)

Target Class:	Residential
VA Program Type:	Demand Response
NC Program Type:	Demand Response
VA Duration:	Re-Proposed
NC Duration:	Future

Program Description:

All residential customers who are not already participating in the Company's DSM Phase I Smart Cooling Rewards Program and who have a qualifying smart thermostat would be offered the opportunity to enroll in the peak demand response portion of the Program. Demand Response will be called by the Company during times of peak system demand throughout the year and thermostats of participating customers would be gradually adjusted to achieve a specified amount of load reduction while maintaining reasonable customer comfort and allowing customers to opt-out of specific events if they choose to do so.

Residential Smart Thermostat Program (EE)

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Re-Proposed
NC Duration:	Future

Program Description:

This Program provides an incentive to customers to either purchase a qualifying smart thermostat and/or enroll in an energy efficiency program, which helps customers manage their daily heating and cooling energy usage by allowing remote optimization of their thermostat operation, and provides specific recommendations by e-mail or letter that customers can act on to realize additional energy savings. The Program is open to several thermostat manufacturers, makes, and models that meet or exceed the Energy Star requirements and have communicating technology. Rebates for the purchase of a smart thermostat are provided on a one-time basis; incentives for participation in remote thermostat management are provided on an annual basis. For those customers who are enrolled in thermostat management, additional energy-saving suggestions based on operational data specific to the customer's heating and cooling system are provided to the customer at least quarterly.

Appendix 6B – Approved Programs Non-Coincidental Peak Savings for Plan B (kW) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Air Conditioner Cycling Program	53,826	53,826	53,826	53,826	53,826	55,522	57,611	58,468	56,259	53,826	53,826	53,826	53,826	53,826	53,826	53,826
Residential Low Income Program	4,077	4,077	4,077	4,077	4,039	3,509	2,233	1,436	795	192	0	0	0	0	0	0
Residential Lighting Program	19,434	9,766	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	9,158	6,821	2,410	86	67	0	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	668	668	668	668	668	655	495	193	0	0	0	0	0	0	0	0
Non-Residential Energy Audit Program	4,720	3,687	803	392	0	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029	121,029
Non-Residential Distributed Generation Program	9,463	9,463	10,514	10,514	11,566	11,608	11,650	11,681	11,713	11,744	11,776	11,807	11,839	11,870	11,902	11,934
Residential Bundle Program	18,876	14,987	13,139	13,114	12,835	11,135	9,823	8,577	8,325	7,129	5,768	3,977	1,413	832	259	0
Residential Home Energy Check-Up Program	4,685	4,685	4,685	4,659	4,381	2,681	1,369	125	0	0	0	0	0	0	0	0
Residential Duct Sealing Program	1,555	1,555	1,555	1,555	1,555	1,555	1,555	1,555	1,555	1,555	1,553	1,526	1,413	832	259	0
Residential Heat Pump Tune Up Program	5,736	1,847	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	6,900	6,900	6,900	6,900	6,900	6,900	6,900	6,897	6,770	5,575	4,215	2,451	0	0	0	0
Non-Residential Window Film Program	7,122	7,122	7,122	7,122	6,660	5,484	4,381	2,006	269	24	0	0	0	0	0	0
Non-Residential Lighting Systems & Controls Program	59,716	59,716	59,716	58,711	53,744	38,257	23,583	13,085	6,043	6,043	6,043	6,043	6,043	6,043	6,043	6,043
Non-Residential Heating and Cooling Efficiency Program	30,512	30,512	30,512	30,512	30,512	30,512	30,512	30,512	30,512	30,476	29,373	21,046	14,111	6,604	1,193	0
Income and Age Qualifying Home Improvement Program	2,510	2,862	3,214	3,566	3,918	4,153	4,179	4,206	4,231	4,256	4,280	4,674	4,462	4,380	4,404	4,425
Residential Appliance Recycling Program	1,762	1,762	1,762	1,528	860	0	0	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	22,829	24,701	25,190	25,691	26,202	26,461	26,592	26,720	26,844	26,965	27,076	29,618	28,590	27,150	27,262	27,372
Residential Retail LED Lighting Program (NC only)	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651
Non-Residential Prescriptive Program	7,591	9,145	9,893	10,042	10,250	10,304	10,380	10,455	10,527	10,598	10,668	10,736	10,803	10,869	10,934	10,999
Residential Efficient Products Marketplace Program	176,553	265,923	363,458	469,989	475,487	480,906	486,283	491,480	496,455	501,300	506,035	510,655	515,175	519,604	523,959	528,257
Residential Customer Engagement Program	19,648	18,958	17,653	16,436	15,302	19,648	18,958	17,653	16,436	15,302	19,648	18,958	17,653	16,436	15,302	19,648
Non-Residential Lighting Systems & Controls Program	3,296	4,389	5,576	6,764	6,863	6,926	6,988	7,049	7,108	7,166	7,223	7,278	7,333	7,387	7,441	7,494
Residential Appliance Recycling Program	1,215	2,084	2,989	3,916	4,331	4,380	4,428	4,440	4,521	4,565	4,608	4,650	4,691	4,731	4,770	4,809
Non-Residential Heating and Cooling Efficiency Program	10,232	17,054	23,875	30,697	36,894	37,392	37,732	38,069	38,240	38,716	39,028	39,335	39,478	39,934	40,227	40,516
Non-Residential Window Film Program	718	1,194	1,639	1,902	1,424	1,257	1,268	1,279	1,472	1,298	1,308	1,317	1,517	1,337	1,347	1,356
Residential Home Energy Assessment Program	896	1,906	4,411	3,957	4,828	4,885	4,940	4,995	5,047	5,098	5,147	5,195	5,243	5,289	5,334	5,378
Residential Smart Thermostat Management Program (DR)	12,308	37,375	53,941	69,556	81,985	82,919	83,846	84,742	85,600	86,436	87,252	88,049	88,828	89,592	90,343	91,084
Residential Smart Thermostat Management Program (EE)	581	1,755	2,798	3,787	4,751	5,207	5,266	5,324	5,380	5,433	5,486	5,537	5,587	5,636	5,683	5,731
Non-Residential Office Program	1,729	2,950	4,170	5,390	6,382	6,443	6,503	6,564	6,625	6,682	6,738	6,793	6,847	6,900	6,952	7,003
Non-Residential Small Manufacturing Program	1,466	2,444	3,421	4,399	4,516	4,557	4,598	4,639	4,678	4,716	4,754	4,791	4,827	4,863	4,898	4,933
Total	**603,587**	**717,826**	**829,458**	**959,322**	**980,591**	**974,801**	**964,932**	**956,253**	**949,761**	**950,644**	**958,715**	**956,966**	**950,946**	**945,963**	**944,759**	**953,489**

Note: Values reflective of free-ridership.

Appendix 6C– Approved Programs Coincidental Peak Savings for Plan B (kW) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Air Conditioner Cycling Program	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826	53,826
Residential Low Income Program	2,344	2,344	2,344	2,344	2,191	1,639	1,051	642	273	50	0	0	0	0	0	0
Residential Lighting Program	10,398	3,152	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	9,154	5,328	1,335	86	36	0	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	668	668	668	668	668	582	339	88	0	0	0	0	0	0	0	0
Non-Residential Energy Audit Program	4,523	2,248	628	214	0	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595	7,595
Non-Residential Distributed Generation Program	9,025	9,463	10,076	10,514	11,127	11,590	11,632	11,668	11,700	11,731	11,763	11,794	11,826	11,857	11,889	11,920
Residential Bundle Program	13,347	9,699	7,965	7,926	7,413	6,701	6,064	5,746	5,284	4,499	3,532	2,275	1,326	781	243	0
Residential Home Energy Check-Up Program	2,236	2,236	2,235	2,196	1,683	971	334	27	0	0	0	0	0	0	0	0
Residential Duct Sealing Program	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,457	1,432	1,326	781	243	0
Residential Heat Pump Tune Up Program	5,381	1,733	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	4,272	4,272	4,272	4,272	4,272	4,272	4,272	4,261	3,825	3,041	2,075	843	0	0	0	0
Non-Residential Window Film Program	5,211	5,211	5,211	5,211	4,873	4,012	3,205	1,468	197	18	0	0	0	0	0	0
Non-Residential Lighting Systems & Controls Program	34,310	34,310	34,310	33,805	28,074	18,903	11,277	5,589	3,472	3,472	3,472	3,472	3,472	3,472	3,472	3,472
Non-Residential Heating and Cooling Efficiency Program	7,058	7,058	7,058	7,058	7,058	7,058	7,058	7,058	7,058	6,999	5,816	4,074	2,378	859	125	0
Income and Age Qualifying Home Improvement Program	983	1,121	1,259	1,397	1,535	1,598	1,608	1,617	1,626	1,634	1,638	1,617	1,588	1,580	1,585	1,592
Residential Appliance Recycling Program	1,744	1,744	1,744	1,513	788	0	0	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	13,336	15,213	15,513	15,820	16,135	16,314	16,394	16,473	16,549	16,624	16,692	16,689	16,668	16,708	16,777	16,845
Residential Retail LED Lighting Program (NC only)	755	755	755	755	755	755	755	755	755	755	755	755	755	755	755	755
Non-Residential Prescriptive Program	5,899	7,152	7,742	7,859	7,979	8,064	8,123	8,182	8,238	8,294	8,348	8,401	8,454	8,506	8,557	8,607
Residential Efficient Products Marketplace Program	1,673	2,650	3,740	4,931	5,483	5,546	5,608	5,669	5,728	5,785	5,840	5,894	5,947	5,999	6,050	6,100
Residential Customer Engagement Program	15,236	14,701	13,689	12,745	11,866	15,236	14,701	13,689	12,745	11,866	15,236	14,701	13,689	12,745	11,866	15,236
Non-Residential Lighting Systems & Controls Program	2,947	4,952	6,448	7,945	8,615	8,694	8,772	8,850	8,925	8,998	9,070	9,140	9,210	9,278	9,346	9,412
Residential Appliance Recycling Program	1,124	2,041	2,959	3,877	4,287	4,336	4,384	4,396	4,476	4,519	4,562	4,603	4,644	4,683	4,722	4,761
Non-Residential Heating and Cooling Efficiency Program	2,040	3,922	5,805	7,688	8,518	8,597	8,674	8,751	8,825	8,897	8,968	9,038	9,107	9,175	9,241	9,307
Non-Residential Window Film Program	496	949	1,402	1,855	2,054	2,073	2,092	2,111	2,128	2,146	2,163	2,180	2,196	2,213	2,229	2,245
Residential Home Energy Assessment Program	1,765	4,471	9,388	13,174	14,721	14,891	15,059	15,223	15,380	15,533	15,681	15,827	15,969	16,108	16,244	16,378
Residential Smart Thermostat Management Program (DR)	7,180	26,931	47,038	63,049	76,806	82,530	83,460	84,369	85,243	86,088	86,912	87,717	88,503	89,273	90,030	90,775
Residential Smart Thermostat Management Program (EE)	286	1,065	1,898	2,614	3,282	3,573	3,614	3,653	3,691	3,727	3,763	3,798	3,832	3,865	3,898	3,930
Non-Residential Office Program	454	874	1,294	1,713	1,898	1,916	1,933	1,950	1,966	1,983	1,998	2,014	2,029	2,044	2,059	2,074
Non-Residential Small Manufacturing Program	755	1,451	2,148	2,845	3,152	3,181	3,210	3,238	3,266	3,292	3,319	3,344	3,370	3,395	3,420	3,444
Total	214,130	230,893	253,839	279,027	290,735	289,209	280,434	272,603	268,947	268,331	270,949	268,756	266,384	264,717	263,928	268,276

Note: Values reflective of free-ridership.

Appendix 6D – Approved Programs Energy Savings for Plan B
(MWh) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Low Income Program	10,435	10,435	10,435	10,435	9,827	7,512	4,811	2,961	1,322	257	0	0	0	0	0	0
Residential Lighting Program	111,791	36,179	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	60,617	36,203	9,453	567	258	0	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	4,732	4,719	4,719	4,719	4,732	4,152	2,484	676	0	0	0	0	0	0	0	0
Non-Residential Energy Audit Program	35,976	18,719	5,087	1,810	0	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567	80,567
Non-Residential Distributed Generation Program	118	1,136	133	690	381	707	1,393	687	860	707	762	1,412	1,415	1,419	1,423	1,427
Residential Bundle Program	49,096	43,799	41,152	40,788	35,979	28,684	22,258	18,845	17,085	14,055	10,371	5,631	1,743	1,050	329	0
Residential Home Energy Check-Up Program	22,584	22,584	22,577	22,212	17,403	10,109	3,683	307	0	0	0	0	0	0	0	0
Residential Duct Sealing Program	1,912	1,912	1,912	1,912	1,912	1,912	1,912	1,912	1,912	1,912	1,910	1,878	1,743	1,050	329	0
Residential Heat Pump Tune Up Program	7,937	2,640	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	16,663	16,663	16,663	16,663	16,663	16,663	16,663	16,626	15,173	12,143	8,461	3,752	0	0	0	0
Non-Residential Window Film Program	5,598	5,598	5,598	5,598	5,234	4,308	3,442	1,572	211	19	0	0	0	0	0	0
Non-Residential Lighting Systems & Controls Program	203,441	203,441	203,441	200,683	168,998	114,603	68,666	34,535	20,588	20,588	20,588	20,588	20,588	20,588	20,588	20,588
Non-Residential Heating and Cooling Efficiency Program	34,035	34,035	34,035	34,035	34,035	34,035	34,035	34,035	34,035	33,797	28,895	20,334	12,234	4,720	735	0
Income and Age Qualifying Home Improvement Program	10,240	11,725	13,210	14,695	16,180	16,942	17,043	17,142	17,237	17,329	17,383	17,238	16,999	16,927	16,985	17,066
Residential Appliance Recycling Program	11,484	11,484	11,484	10,034	5,368	0	0	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	72,728	84,085	85,739	87,433	89,165	90,216	90,659	91,094	91,517	91,929	92,304	92,252	92,039	92,215	92,595	92,971
Residential Retail LED Lighting Program (NC only)	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269	7,269
Non-Residential Prescriptive Program	14,949	18,142	19,713	20,011	20,316	20,537	20,688	20,837	20,982	21,123	21,261	21,398	21,531	21,663	21,793	21,922
Residential Efficient Products Marketplace Program	128,674	205,013	290,431	383,696	430,667	435,634	440,548	445,355	449,977	454,442	458,799	463,054	467,211	471,282	475,278	479,215
Residential Customer Engagement Program	50,810	49,025	45,649	42,503	39,570	50,810	49,025	45,649	42,503	39,570	50,810	49,025	45,649	42,503	39,570	50,810
Non-Residential Lighting Systems & Controls Program	14,217	24,407	31,857	39,307	42,880	43,275	43,666	44,051	44,425	44,790	45,148	45,499	45,845	46,186	46,522	46,855
Residential Appliance Recycling Program	7,221	13,263	19,304	25,346	28,216	28,535	28,851	28,915	29,456	29,743	30,023	30,296	30,563	30,824	31,081	31,334
Non-Residential Heating and Cooling Efficiency Program	9,095	18,245	27,395	36,546	41,366	41,747	42,124	42,497	42,858	43,211	43,556	43,896	44,230	44,560	44,884	45,205
Non-Residential Window Film Program	2,033	3,897	5,761	7,626	8,454	8,532	8,609	8,685	8,759	8,830	8,901	8,970	9,038	9,106	9,172	9,237
Residential Home Energy Assessment Program	9,326	21,478	35,892	49,014	55,565	56,206	56,840	57,461	58,058	58,634	59,197	59,746	60,283	60,808	61,324	61,832
Residential Smart Thermostat Management Program (DR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Smart Thermostat Management Program (EE)	1,594	6,244	11,660	16,433	21,075	23,444	23,708	23,967	24,217	24,457	24,692	24,921	25,145	25,364	25,580	25,792
Non-Residential Office Program	5,212	10,387	15,562	20,737	23,397	23,613	23,827	24,037	24,241	24,440	24,636	24,828	25,017	25,203	25,387	25,569
Non-Residential Small Manufacturing Program	3,521	6,896	10,270	13,645	15,262	15,402	15,542	15,679	15,812	15,941	16,069	16,194	16,317	16,439	16,559	16,677
Total	944,780	966,392	1,025,820	1,154,187	1,184,761	1,136,731	1,086,055	1,046,517	1,031,979	1,031,699	1,041,229	1,033,118	1,023,685	1,018,693	1,017,641	1,034,336

Note: Values reflective of free-ridership.

Appendix 6E – Approved Programs Penetrations for Plan B
(System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Air Conditioner Cycling Program	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
Residential Low Income Program	12,743	12,743	12,743	12,743	11,312	7,192	4,656	2,653	653	0	0	0	0	0	0	0
Residential Lighting Program	2,243,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	2,057	749	21	21	0	0	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	127	127	127	127	127	99	40	0	0	0	0	0	0	0	0	0
Non-Residential Energy Audit Program	1,437	305	154	17	0	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694
Non-Residential Distributed Generation Program	9	9	10	10	11	11	11	11	11	11	11	11	11	11	11	11
Residential Bundle Program	98,903	78,621	75,993	74,424	54,722	39,866	24,610	22,975	19,680	15,987	11,172	5,004	3,336	1,153	278	0
Residential Home Energy Check-Up Program	52,963	52,963	52,932	51,363	31,661	16,805	1,549	0	0	0	0	0	0	0	0	0
Residential Duct Sealing Program	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,845	3,737	3,336	1,153	278	0
Residential Heat Pump Tune Up Program	22,879	2,597	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	19,208	19,208	19,208	19,208	19,208	19,208	19,208	19,122	15,827	12,134	7,327	1,267	0	0	0	0
Non-Residential Window Film Program	476,780	476,780	476,780	476,780	423,759	326,638	269,410	37,776	3,913	0	0	0	0	0	0	0
Non-Residential Lighting Systems & Controls Program	4,674	4,674	4,674	4,556	3,302	2,056	1,165	473	473	473	473	473	473	473	473	473
Non-Residential Heating and Cooling Efficiency Program	422	422	422	422	422	422	422	422	422	416	299	204	98	18	0	0
Income and Age Qualifying Home Improvement Program	30,294	34,794	39,294	43,794	48,294	48,602	48,907	49,202	49,485	49,760	50,029	50,291	50,548	50,799	51,046	51,290
Residential Appliance Recycling Program	14,072	14,072	14,072	10,866	3,131	0	0	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	4,145	4,228	4,313	4,400	4,489	4,512	4,534	4,556	4,577	4,598	4,618	4,638	4,658	4,677	4,697	4,716
Residential Retail LED Lighting Program (NC only)	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497	334,497
Non-Residential Prescriptive Program	2,336	2,792	2,834	2,877	2,921	2,943	2,964	2,985	3,006	3,026	3,045	3,065	3,084	3,102	3,121	3,139
Residential Efficient Products Marketplace Program	5,284,607	7,959,658	10,879,110	14,067,818	14,232,435	14,394,619	14,555,576	14,711,134	14,860,043	15,005,051	15,146,784	15,285,084	15,420,379	15,552,950	15,683,296	15,811,937
Residential Customer Engagement Program	287,500	277,400	258,300	240,500	223,900	287,500	277,400	258,300	240,500	223,900	287,500	277,400	258,300	240,500	223,900	287,500
Non-Residential Lighting Systems & Controls Program	998	1,364	1,730	2,096	2,116	2,135	2,154	2,173	2,191	2,209	2,226	2,243	2,260	2,277	2,293	2,309
Residential Appliance Recycling Program	15,589	25,089	34,589	44,089	44,595	45,093	45,588	46,066	46,523	46,969	47,404	47,829	48,245	48,652	49,053	49,448
Non-Residential Heating and Cooling Efficiency Program	1,050	1,750	2,450	3,150	3,179	3,208	3,237	3,265	3,292	3,319	3,345	3,371	3,396	3,421	3,446	3,471
Non-Residential Window Film Program	202,350	336,300	470,250	604,200	609,825	615,383	620,912	626,306	631,524	636,640	641,671	646,613	651,477	656,270	661,005	665,695
Residential Home Energy Assessment Program	41,387	76,407	110,455	144,863	146,558	148,228	149,886	151,488	153,021	154,514	155,974	157,398	158,791	160,156	161,498	162,823
Residential Smart Thermostat Management Program (DR)	6,808	20,673	29,836	38,473	45,348	45,865	46,378	46,873	47,348	47,810	48,261	48,702	49,133	49,555	49,971	50,381
Residential Smart Thermostat Management Program (EE)	9,071	27,173	40,828	54,200	66,569	67,328	68,080	68,808	69,504	70,183	70,846	71,493	72,125	72,745	73,355	73,957
Non-Residential Office Program	126	210	294	378	382	385	388	392	395	398	401	405	408	411	414	416
Non-Residential Small Manufacturing Program	105	175	245	315	318	321	324	327	329	332	335	337	340	342	345	347
Total	9,164,931	9,780,706	12,883,715	16,255,310	16,351,906	16,466,596	16,550,833	16,460,375	16,561,082	16,689,785	16,898,586	17,028,752	17,151,253	17,271,705	17,392,392	17,592,105

Note: Values reflective of free-ridership.

Appendix 6F – Description of Proposed Programs

Residential Electric Vehicle EE/DR Program

State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Residential Electric Vehicle Program would provide an incentive to customers to purchase a qualifying charger for their electric vehicle and who agree to enroll in the demand response ("DR") component of the proposed program. Customers who receive an incentive for the purchase of the qualifying chargers must also participate in the DR component of the program. Demand response would be called by the Company during times of peak system demand throughout the year and vehicle chargers enrolled in the Program would be activated by remote control to temporarily reduce load. Customers can opt-out of specific events if they choose to do so.

Residential Electric Vehicle Peak Shaving Program

State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Peak Shaving
NC Program Type:	Peak Shaving
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Residential Electric Vehicle Peak Shaving Program is for customers who already have a qualifying Level 2 charger and wish to participate in the demand response component only (no purchase incentive).

Appendix 6F cont. – Description of Proposed Programs

Residential Energy Efficiency Kits Program

State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Residential Energy Efficiency Kits Program would provide residential customers with newly connected homes the opportunity to receive Welcome Kits. The Welcome kit will initially include a Tier I advanced power strip and an educational insert informing customers about opportunities to manage their energy use and how to opt into receiving additional free measures by going online to the program website or calling the program hotline. To receive the additional measures, customers will have to confirm their address and account status and answer a few questions to confirm the measures will be of value in producing electric energy savings in the home. Additionally, customers will receive educational materials on proper use of each measure, energy use in general, and energy savings available through other Company DSM programs.

Residential Home Retrofit Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Residential Home Retrofit Program would target high users of electricity within the Company's Virginia service territory with an incentive to conduct a comprehensive and deep whole house diagnostic home energy assessment by BPI certified whole house building technicians. The diagnostic-driven audit will typically take between 2 ½ and 4 hours depending on home size, and will include: visual inspection of all areas of the home including attic and crawl spaces; blower door testing of envelope leakage; duct blaster equivalent testing of ducting system if present; line logger testing of major appliances; thermal imaging where required; physical measurements of key spaces and insulation levels; and efficiency determinations of major equipment.

Appendix 6F cont. – Description of Proposed Programs

Residential Manufactured Housing Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Residential Manufactured Housing Program would provide residential customers in manufactured housing with educational assistance and an incentive to install energy efficiency measures. The auditor will perform a walk-through audit covering the envelope and all energy systems in the home, paying particular attention to the condition of DHW and HVAC systems, levels of insulation, and the condition of belly board. The contractor will be required to use the Program's energy analysis software to collect required data to perform energy calculations and generate a detailed report showing projected energy and potential cost savings specific to each customer's home. The intuitive audit software calculates and captures measure level savings values, which produces a consumer-friendly report outlining energy savings recommendations. The auditor will review the findings and recommendations of the complete report with the homeowner. The auditor will utilize a user-friendly audit software that calculates and captures measure-level savings values and produces a consumer-friendly report that clearly outlines additional energy savings recommendations. The auditor will review the findings and recommendations of the complete report with the homeowner.

Residential New Construction Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Residential New Construction Program will provide incentives to home builders for the construction of new homes that are ENERGY STAR certified by directly recruiting existing networks of homebuilders and Home Energy Rating System ("HERS") Raters to build and inspect ENERGY STAR Certified New Homes. ENERGY STAR certification requires that homes be efficient at the system level instead of a menu-based offering. ENERGY STAR certification of new homes involves a whole-house set of standards that ensure homes are at least 15% more efficient than a home built to state-level minimum codes. Key components include: Shell improvements, HVAC performance, proper ventilation requirements (supports healthy indoor environments in certified homes) and durability (proper weather sealing, flashing details, site and foundation details). Participating homes must submit an energy model developed using Ekotrope or REM/Rate energy modeling software, along with a copy of the home's ENERGY STAR certificate (both provided by the rater) in order to qualify for an incentive.

Appendix 6F cont. – Description of Proposed Programs

Residential/Non-Residential Multifamily Program

Target Class:	Residential/Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Multifamily Program is designed to encourage investment in both residential and commercial *(i.e.,* common spaces) service aspects of multifamily properties. The Program design is based on a whole building approach where the implementation vendor will identify as many cost-effective measure opportunities as possible in the entire building (both residential and commercial meter) and encourage property owners to address the measures as a bundle. This approach provides one-stop-shop programming for multifamily property owners with solutions to include direct install-in-unit measures and incentives for prescriptive efficiency improvements. The Program will identify, track and report residential (in-unit) and commercial (common space) savings separately according to the account type.

Non-Residential Midstream EE Products Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Non-Residential Midstream EE Products Program consists of enrolling equipment distributors into the Program through an agreement to provide point-of-sales data in an agreed upon format each month. These monthly data sets will contain, at minimum, the data necessary to validate and quantify the eligible equipment that has been delivered for sale in the Company's service territory. In exchange for the data sets, the distributor will discount the rebate-eligible items sold to end customers. This Program aims to increase the availability and uptake of efficient equipment for the Company’s non-residential customers.

Appendix 6F cont. – Description of Proposed Programs

Non-Residential New Construction Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Non-Residential New Construction Program would provide qualifying facility owners with incentives to install energy efficient measures in their new construction project. Program engineers will determine what potential energy efficiency upgrades are of interest to the owner and feasible within their budget. These measures coupled with basic facility design data will be analyzed to determine the optimized building design. This in-depth analysis will be performed using building energy simulation models, which will allow for "bundles" of measures to be tested for potential energy savings gains from interactive effects. The results will be presented to the facility owner to determine which measures are to be installed. Program design building types modeled include small offices, medium offices, stand-alone retail, and outpatient health care.

Small Business Improvement Enhanced Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Small Business Improvement Enhanced Program would provide small businesses an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for the installation of specific energy efficiency measures. Participating small businesses would be required to meet certain size and connected load requirements.

Appendix 6F cont. – Description of Proposed Programs

House Bill 2789 Program (Heating and Cooling/Health and Safety Component)

Target Class:	Residential/Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The Heating and Cooling/Health and Safety Component of Virginia House Bill 2789 requires that a petition be submitted for a program for income qualifying, elderly and disabled individuals. This component would offer incentives for the installation of measures that reduce residential heating and cooling costs and enhance the health and safety of residents, including repairs and improvements to home heating and cooling systems and installation of energy-saving measures in the house, such as insulation and air sealing.

Appendix 6G – Proposed Programs Non-Coincidental Peak Savings for Plan B (kW) (System Level)

Programs	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Non-Residential Midstream EE Products	0	0	1,741	4,274	6,973	9,672	12,371	13,567	13,686	13,802	13,916	14,027	14,136	14,243	14,349	14,453	14,557
Non-Residential New Construction	0	0	221	790	1,953	3,738	5,603	6,633	6,692	6,750	6,806	6,862	6,916	6,969	7,021	7,073	7,124
Residential EE Kits	0	0	2,494	4,987	7,480	9,974	12,467	12,607	12,742	12,871	12,996	13,119	13,239	13,356	13,471	13,584	13,695
Residential Home Retrofit	0	0	415	1,339	2,570	4,216	5,984	6,765	6,839	6,910	6,978	7,045	7,110	7,174	7,236	7,298	7,358
Residential Manufactured Housing	0	0	467	1,494	2,614	3,840	5,157	5,743	5,805	5,865	5,924	5,980	6,036	6,090	6,143	6,195	6,246
Multifamily Program	0	0	2,198	6,320	11,411	16,501	21,592	23,873	24,128	24,374	24,611	24,843	25,070	25,291	25,508	25,721	25,931
HB 2789 HVAC Component	0	0	6,690	13,380	23,002	31,848	31,848	31,848	31,848	31,848	31,848	31,848	31,848	31,848	31,848	31,848	31,848
Residential New Construction	0	0	2,325	5,770	9,645	13,842	18,157	20,085	20,304	20,514	20,718	20,916	21,110	21,299	21,484	21,666	21,846
Non-Residential Small Business Improvement Enhanced	0	0	784	2,339	3,894	5,530	7,251	8,622	8,699	8,774	8,847	8,918	8,988	9,057	9,125	9,192	9,258
Residential Electric Vehicle EE/DR	0	0	803	1,895	3,566	6,063	9,731	9,849	9,954	10,055	10,153	10,249	10,343	10,435	10,524	10,612	10,700
Residential Electric Vehicle Peak Shaving	0	0	134	244	412	664	1,034	1,045	1,056	1,067	1,077	1,088	1,098	1,107	1,117	1,126	1,135
Total	0	0	18,272	42,832	73,520	105,889	131,198	140,638	141,755	142,832	143,875	144,895	145,893	146,869	147,827	148,769	149,698

Note: Values reflective of free-ridership.

Appendix 6H – Proposed Programs Coincidental Peak Savings for Plan B (kW) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Non-Residential Midstream EE Products	0	1,550	4,207	6,865	9,522	12,179	13,356	13,474	13,588	13,699	13,809	13,916	14,022	14,126	14,229	14,331
Non-Residential New Construction	0	129	544	1,420	2,850	4,510	5,228	5,275	5,319	5,363	5,406	5,448	5,489	5,530	5,570	5,610
Residential EE Kits	0	432	1,172	1,913	2,653	3,393	3,726	3,766	3,805	3,843	3,880	3,916	3,951	3,985	4,019	4,052
Residential Home Retrofit	0	306	1,203	2,536	4,161	5,907	6,678	6,750	6,820	6,888	6,954	7,018	7,081	7,143	7,203	7,263
Residential Manufactured Housing	0	274	1,071	2,158	3,285	4,411	4,912	4,965	5,017	5,066	5,115	5,162	5,209	5,254	5,298	5,342
Multifamily Program	0	1,891	6,187	11,234	16,282	21,329	23,582	23,834	24,077	24,311	24,540	24,764	24,983	25,197	25,407	25,615
HB 2789 HVAC Component	0	1,208	3,279	5,350	6,213	6,213	6,213	6,213	6,213	6,213	6,213	6,213	6,213	6,213	6,213	6,213
Residential New Construction	0	1,934	5,384	9,075	13,025	17,085	18,899	19,105	19,303	19,494	19,681	19,863	20,041	20,216	20,387	20,556
Non-Residential Small Business Improvement Enhanced	0	1,816	4,930	8,043	11,156	14,270	15,649	15,787	15,920	16,051	16,179	16,305	16,429	16,551	16,671	16,790
Residential Electric Vehicle EE/DR	0	344	1,059	2,109	3,692	6,029	7,199	7,277	7,353	7,426	7,497	7,566	7,634	7,700	7,766	7,830
Residential Electric Vehicle Peak Shaving	0	60	151	262	427	673	796	804	813	821	829	836	844	851	858	865
Total	0	9,943	29,187	50,966	73,265	95,999	106,238	107,251	108,228	109,176	110,102	111,008	111,896	112,766	113,623	114,467

Note: Values reflective of free-ridership.

Appendix 6I – Proposed Programs Energy Savings for Plan B
(MWh) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Non-Residential Midstream EE Products	0	2,348	6,392	10,435	14,478	18,522	20,322	20,502	20,675	20,845	21,011	21,175	21,336	21,494	21,651	21,805
Non-Residential New Construction	0	564	2,437	6,415	12,961	20,663	24,255	24,468	24,676	24,879	25,078	25,273	25,465	25,654	25,841	26,026
Residential EE Kits	0	4,539	12,882	21,226	29,569	37,913	41,971	42,429	42,870	43,295	43,710	44,115	44,512	44,899	45,280	45,655
Residential Home Retrofit	0	1,033	4,137	8,803	14,492	20,630	23,471	23,727	23,973	24,210	24,442	24,669	24,890	25,107	25,320	25,530
Residential Manufactured Housing	0	1,037	4,147	8,457	12,932	17,407	19,513	19,726	19,931	20,128	20,321	20,510	20,694	20,874	21,051	21,225
Multifamily Program	0	5,776	19,341	35,454	51,568	67,681	75,245	76,035	76,796	77,533	78,252	78,955	79,643	80,317	80,980	81,633
HB 2789 HVAC Component	0	3,005	9,459	15,913	19,362	19,362	19,362	19,362	19,362	19,362	19,362	19,362	19,362	19,362	19,362	19,362
Residential New Construction	0	3,467	9,948	16,883	24,302	31,943	35,557	35,945	36,318	36,678	37,030	37,373	37,708	38,037	38,359	38,677
Non-Residential Small Business Improvement Enhanced	0	5,742	16,023	26,303	36,583	46,863	51,659	52,114	52,557	52,988	53,411	53,827	54,236	54,639	55,037	55,431
Residential Electric Vehicle EE/DR	0	117	374	751	1,319	2,158	2,623	2,652	2,679	2,706	2,732	2,757	2,782	2,806	2,830	2,854
Residential Electric Vehicle Peak Shaving	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	27,629	85,140	150,640	217,566	283,143	313,979	316,961	319,838	322,625	325,350	328,017	330,629	333,191	335,711	338,197

Note: Values reflective of free-ridership.

Appendix 6J – Proposed Programs Penetrations for Plan B (System Level)

Programs	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Non-Residential Midstream EE Products	0	0	300	600	900	1,200	1,500	1,513	1,527	1,539	1,552	1,564	1,576	1,588	1,600	1,611	1,623
Non-Residential New Construction	0	0	20	70	170	320	470	474	478	482	486	490	494	498	501	505	508
Residential EE Kits	0	0	30,000	60,000	90,000	120,000	150,000	151,677	153,298	154,850	156,361	157,838	159,279	160,689	162,070	163,429	164,769
Residential Home Retrofit	0	0	900	2,900	5,400	8,400	11,400	11,527	11,651	11,769	11,883	11,996	12,105	12,212	12,317	12,421	12,522
Residential Manufactured Housing	0	0	1,000	3,200	5,600	8,000	10,400	10,516	10,629	10,736	10,841	10,943	11,043	11,141	11,237	11,331	11,424
Multifamily Program	0	0	10,100	25,825	41,550	57,275	73,000	73,799	74,571	75,311	76,033	76,738	77,427	78,101	78,762	79,412	80,054
HB 2789 HVAC Component	0	0	8,800	17,600	26,400	26,400	26,400	26,400	26,400	26,400	26,400	26,400	26,400	26,400	26,400	26,400	26,400
Residential New Construction	0	0	4,250	8,798	13,664	18,870	24,076	24,345	24,605	24,854	25,097	25,334	25,565	25,792	26,013	26,231	26,447
Non-Residential Small Business Improvement Enhanced	0	0	675	1,350	2,025	2,700	3,375	3,405	3,435	3,464	3,492	3,519	3,546	3,573	3,599	3,625	3,651
Residential Electric Vehicle EE/DR	0	0	1,100	2,596	4,884	8,304	13,328	13,477	13,621	13,759	13,893	14,024	14,153	14,278	14,401	14,521	14,640
Residential Electric Vehicle Peak Shaving	0	0	101	184	311	501	780	789	797	805	813	821	828	836	843	850	857
Total	0	0	57,246	123,123	190,904	251,970	314,729	317,924	321,012	323,970	326,851	329,668	332,417	335,107	337,744	340,336	342,895

Note: Values reflective of free-ridership.

Appendix 6K - Future Undesignated EE Coincidental Peak Savings for Plan B (kW) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
GTSA/VCEA Reductions	0.00	39,000.00	87,000.00	143,000.00	209,000.00	276,000.00	335,000.00	447,000.00	408,000.00	388,000.00	409,000.00	422,000.00	474,000.00	377,000.00	358,000.00	340,000.00

Appendix 6L - Future Undesignated EE Energy Savings for Plan B
(MWh) (System Level)

Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
GTSA/VCEA Reductions	-	190,920	544,938	899,006	1,266,768	1,607,767	1,962,001	2,316,233	2,509,660	2,479,532	2,479,532	2,479,532	2,511,743	2,413,919	2,293,536	2,173,774
Total	**0**	**190,920**	**544,938**	**899,006**	**1,266,768**	**1,607,767**	**1,962,001**	**2,316,233**	**2,509,660**	**2,479,532**	**2,479,532**	**2,479,532**	**2,511,743**	**2,413,919**	**2,293,536**	**2,173,774**

Appendix 6M – Rejected DSM Programs

Program
Non-Residential HVAC Tune-Up Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geothermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors 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
Cool Roof Program
Non-Residential Data Centers Program
Non-Residential Curtailable Service
Non-Residential Custom Incentive
Enhanced Air Conditioner Direct Load Control Program
Residential Programmable Thermostat Program
Residential Controllable Thermostat Program
Residential Retail LED Lighting Program (VA)
Residential New Homes Program
Voltage Conservation
Residential Home Energy Assessment
Non-Residential Re-commissioning Program
Non-Residential Compressed Air System Program
Non-Residential Strategic Energy Management
Non-Residential Agricultural EE
Non-Residential Telecommunication Optimization

National Comparison Analyses

Virginia Electric and Power Company

Section 1: Fuel Source for Generation

The generation mix of a state can be a significant determinant of its electricity cost. Figures 1 and 2 compare Virginia's generation mix with the rest of the country. Virginia's primary source of electricity generation is natural gas, followed by nuclear. This mix is most similar to that of Louisiana and New Jersey. Connecticut, Mississippi, and Rhode Island also have energy generation mixes that may be comparable to Virginia.

Figure 1: Electricity generation mix, as fraction of total

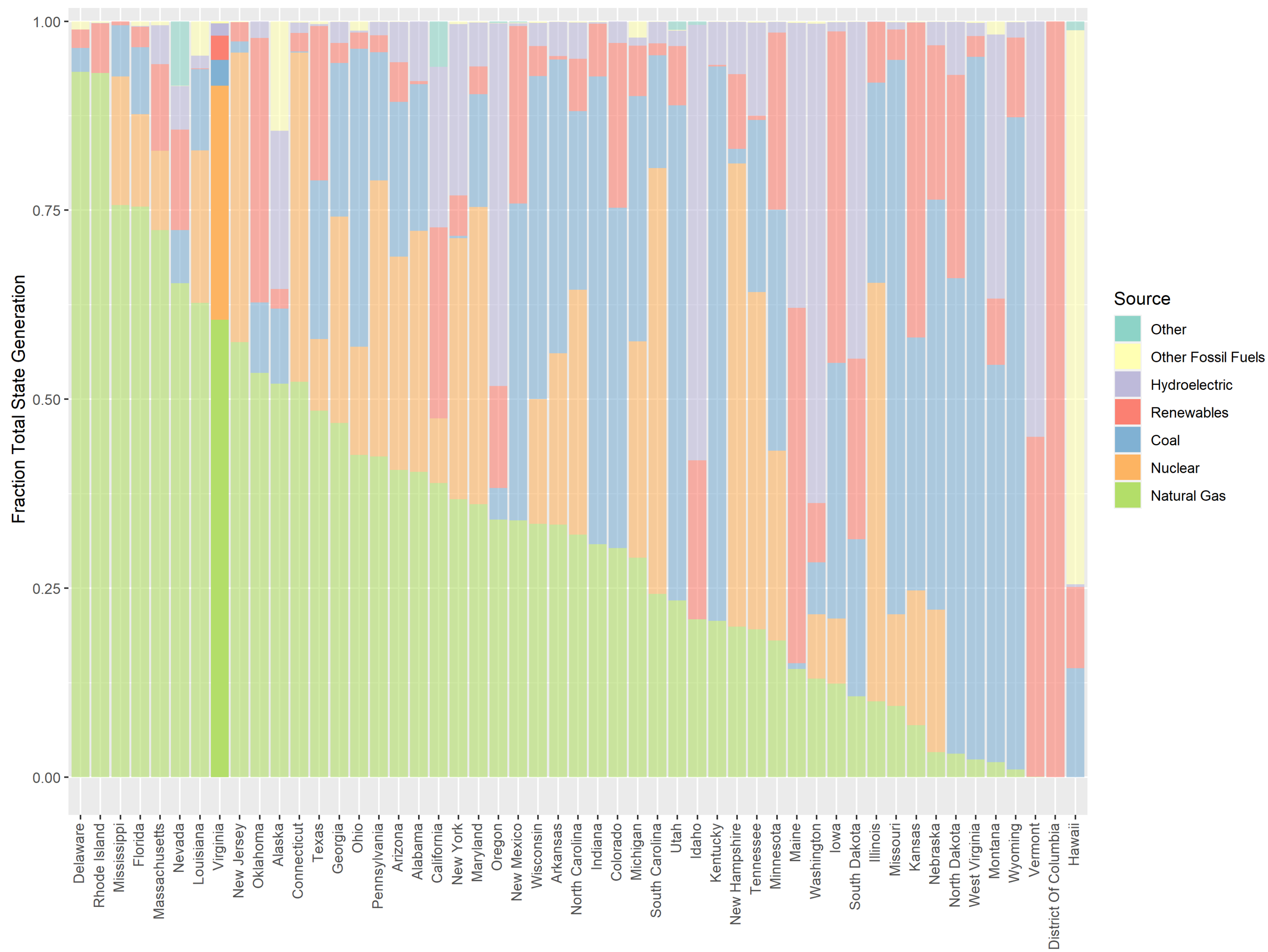
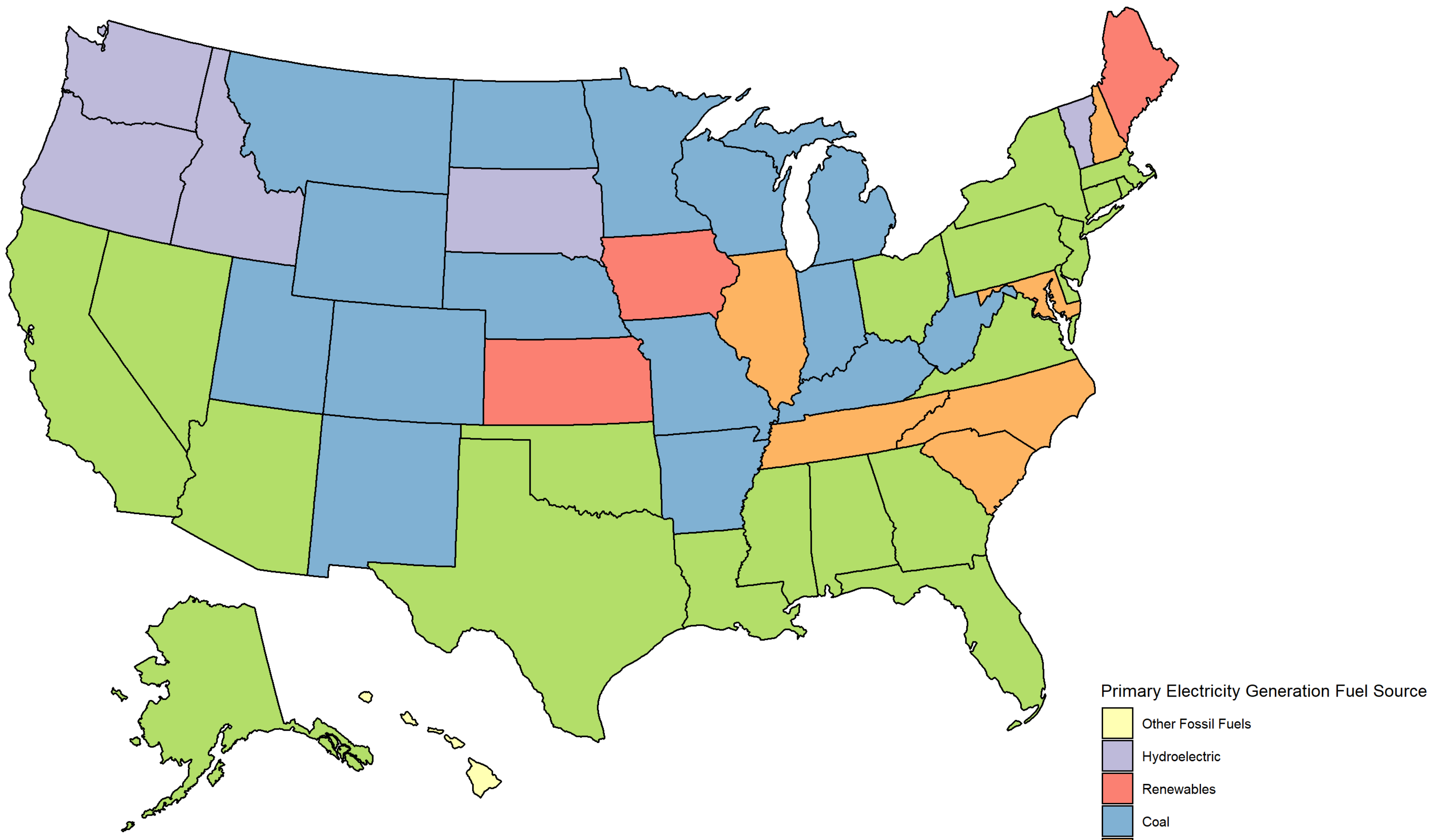


Figure 2: Map of the primary generation fuel source in each state



Section 2: Other Metrics

Variation in electricity bills between states depends in part on the prevalence of electric heating and cooling equipment, cooling and heating loads, and housing size.

Space heating represents a large proportion of many consumers' total energy use. The use of electricity for heating varies widely across regions. Among electrically heated homes, some types of equipment are more efficient than others. Table 1 shows the percentage of different fuels used for home heating in ten Census divisions. Virginia is part of the South Atlantic division that includes Delaware, Maryland, West Virginia, North Carolina, South Carolina, Georgia, Florida, and the District of Columbia. Table **1**2 shows the mix of different heating equipment by Census division. Table 3 shows the mix of different electric heating equipment by Census division. The South Atlantic division has a large fraction of homes heated by electricity compared to the more northern parts of the country. Of those South Atlantic customers who use electric heat, most use either electric central warm-air furnaces or electric heat pumps. The South Atlantic division also has a larger fraction of homes without heating equipment, as compared to the other regions. Relatively fewer customers in the South Atlantic use central warm-air furnaces for heat, and relatively more use heat pumps when compared to other areas.[1]

Table 1: Space heating equipment by fuel source by Census division

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain North	Mountain South	Pacific
Natural gas	37.5%	60.4%	72.9%	66.3%	27.2%	27.8%	37.7%	78.6%	46.5%	48.0%
Electricity	8.9%	14.9%	19.9%	21.7%	55.7%	62.5%	52.9%	14.3%	37.2%	31.3%
Fuel oil/kerosene	39.3%	16.9%	N/A	N/A	3.4%	N/A	N/A	N/A	N/A	N/A
Propane	7.1%	2.6%	5.0%	8.4%	3.4%	6.9%	3.6%	2.4%	N/A	2.2%
Wood	7.1%	3.9%	1.7%	3.6%	2.1%	N/A	1.4%	N/A	N/A	3.9%
Some other fuel[3]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Do not use heating equipment	N/A	N/A	N/A	N/A	8.1%	N/A	3.6%	N/A	4.7%	14.5%

[1] https://www.eia.gov/consumption/residential/data/2015/, tables HC6.7 and HC6.8

Table 1: Saturation of heating equipment types by Census division

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
Central warm-air furnace	57.1%	48.7%	77.3%	73.5%	46.8%	51.4%	68.1%	78.6%	58.1%	51.4%
Heat pump	N/A	4.5%	3.9%	4.8%	26.4%	26.4%	9.4%	N/A	18.6%	7.3%
Steam or hot water system	23.2%	29.2%	6.1%	8.4%	3.0%	N/A	N/A	7.1%	N/A	1.7%
Built-in electric units	N/A	7.8%	8.8%	6.0%	8.5%	8.3%	6.5%	N/A	4.7%	10.1%
Built-in oil or gas room heater	5.4%	3.2%	N/A	N/A	1.3%	5.6%	2.9%	N/A	N/A	4.5%
Portable electric heaters	N/A	N/A	N/A	N/A	3.0%	5.6%	5.8%	N/A	N/A	3.4%
Heating stove burning wood	5.4%	2.6%	1.1%	3.6%	1.7%	N/A	N/A	N/A	N/A	2.8%
Built-in pipeless furnace	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.2%
Fireplace	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.1%
Some other equipment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Do not use heating equipment	N/A	N/A	N/A	N/A	8.1%	N/A	3.6%	N/A	4.7%	14.5%

Table 2: Electric heating equipment mix

		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
Fraction of Homes Heated by Electricity		8.9%	14.9%	19.9%	21.7%	55.7%	62.5%	52.9%	14.3%	37.2%	31.3%
Fraction Electric-Heated Homes Using:	Central warm-air furnace	N/A	13.0%	33.3%	44.4%	35.9%	40.0%	60.3%	50.0%	37.5%	33.9%
	Heat pump	N/A	26.1%	16.7%	16.7%	42.7%	37.8%	15.1%	N/A	43.8%	21.4%
	Built-in electric units	N/A	52.2%	44.4%	27.8%	15.3%	13.3%	12.3%	N/A	12.5%	32.1%
	Portable electric heaters	N/A	N/A	N/A	N/A	5.3%	8.9%	11.0%	N/A	N/A	10.7%
	Some other equipment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Climate is also a key driver of customers' electricity bills. Heating degree days ("HDD") and cooling degree days ("CDD") are often used as proxies for cooling and heating load. It also measures how much the daily temperature diverges from a base temperature (below 65° Fahrenheit for heating and above the 65° Fahrenheit for cooling). Virginia's annual cooling and heating degree days in 2019 were near the US average. In 2019, Virginia had 1,401 CDD compared to the national average of 1,453 CDD and 3,998 HDD compared to the national average of 4,377 HDD.[2]

However, the number of HDD and CDD vary widely across US regions. See Figures 3 and 4. We added Virginia's 2018 CDD and HDD to the maps for comparison.

[2] NNDC Climate Data Online, National Climatic Data Center, U.S. Department of Commerce. https://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp

Figure 3: Cooling degree days by Census division in 2018

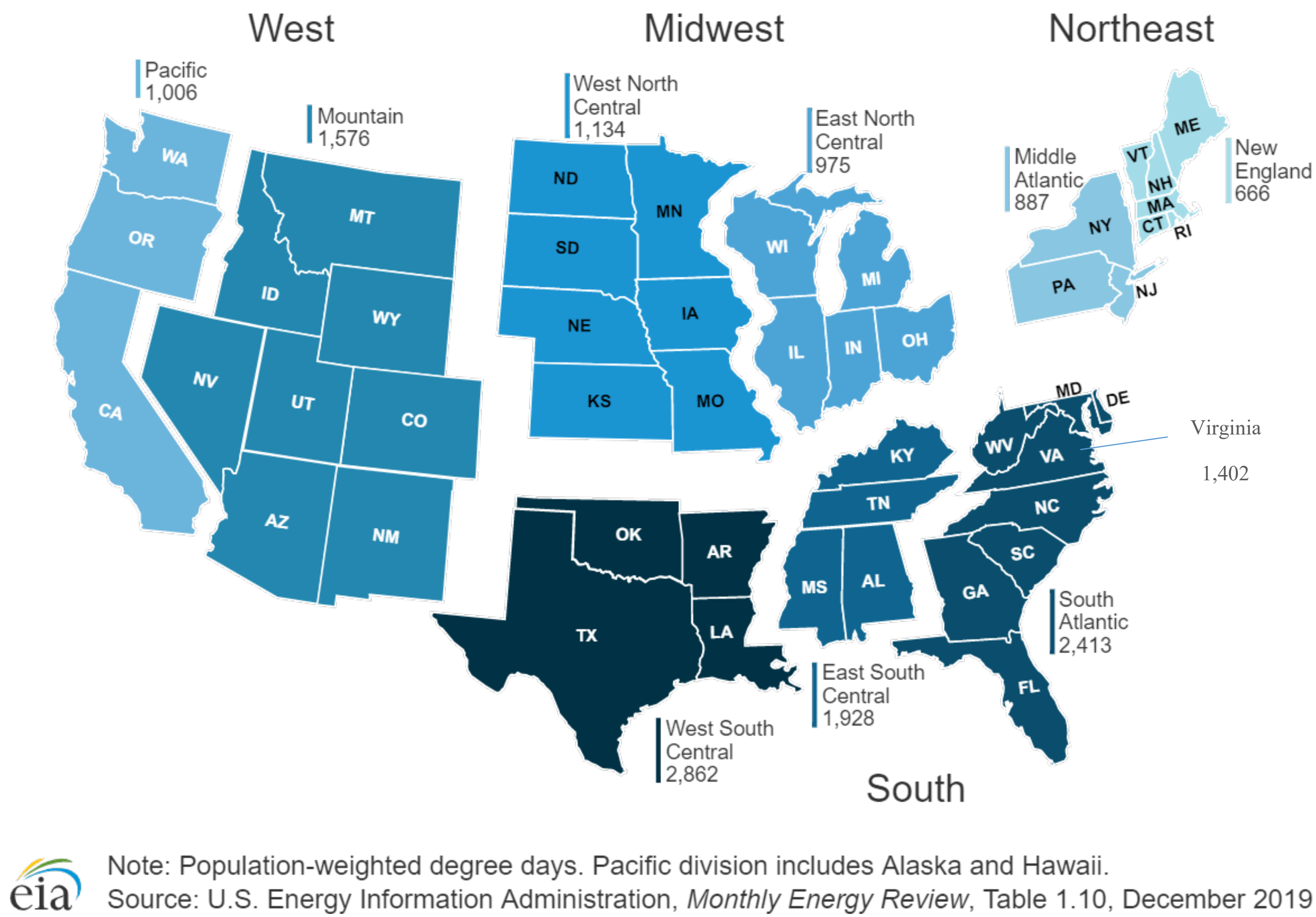
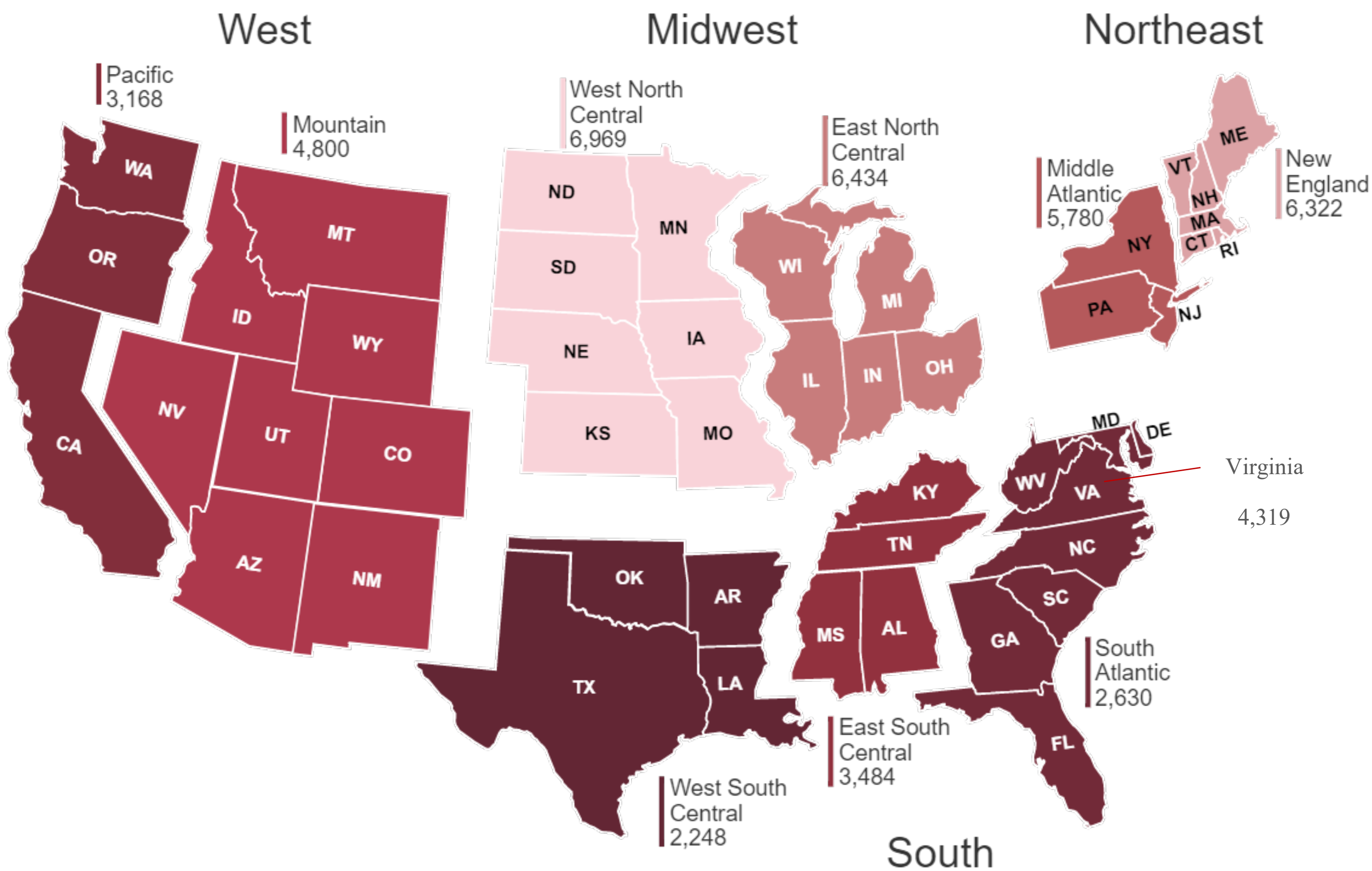


Figure 4: Heating degree days by Census division in 2018



Note: Population-weighted degree days. Pacific division includes Alaska and Hawaii.
Source: U.S. Energy Information Administration, *Monthly Energy Review*, Table 1.9, December 2019

(https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php)

Housing size also affects electricity bills – larger houses require more energy to cool, heat, light, etc. Table 4 shows how housing average square footage varies across the U.S. The South Atlantic division's average home size falls generally in the middle of other Census divisions. The South Atlantic heats fewer square feet/house and cools more square feet/house in comparison to most other parts of the country.[3]

Table 4: Average home size

	Average Square Footage per Housing Unit		
	Total	**Heated**	**Cooled**
All homes	2,008	1,754	1,375
New England	2,186	1,861	783
Middle Atlantic	2,055	1,765	1,100
East North Central	2,250	2,051	1,563
West North Central	2,338	2,024	1,758
South Atlantic	1,999	1,669	1,615
East South Central	1,870	1,625	1,393
West South Central	1,873	1,725	1,592
Mountain North	2,171	2,037	1,294
Mountain South	1,844	1,755	1,427
Pacific	1,689	1,405	947

[3] EIA, https://www.eia.gov/consumption/residential/data/2015/#squarefootage, Table HC10.9

Appendix 7A – List of Transmission Lines Under Construction

Line Terminals	Line Voltage (kV)	Target Date	Location
Sandlot 230 kV Delivery - DEV	230	Mar-20	VA
Freedom Substation (Redundant 69 kV Facility	69	Mar-20	VA
Fork Union Substation – New Substation	115; 230	Apr-20	VA
Line #548 Valley Switching Station Fixed Series Capacitors replacement	500	Apr-20	VA
Line #547 Lexington Substation Fixed Series Capacitors Replacement	500	Apr-20	VA
Line #211 and #228 Chesterfield to Hopewell Partial Rebuild	230	May-20	VA
Line #217 Chesterfield-Lakeside Rebuild	230	May-20	VA
Line #86 Partial Rebuild Project	115	May-20	VA
Line #2199 Remington to Gordonsville– New 230 kV Line	230	May-20	VA
Skippers - New 115 kV Switching Station	115 kV	May-20	VA
Gordonsville Transformer #3 Replacement	230/115	May-20	VA
Idylwood - Convert Straight Bus to Breaker-and-a-Half	230	May-20	VA
Line #549 Dooms to Valley Rebuild	500	Jun-20	VA
Line #76 and #79 Yorktown to Peninsula Rebuild	115	Oct-20	VA
Columbia Tap- CVEC	115	Oct-20	VA
Dawson’s Crossroads – Delivery Point (HEMC)	115	Nov-20	NC
Clarksville Tap Line 193 Rebuild	115	Dec-20	VA
Winters Branch – New Substation	230	Dec-20	VA
Line #154 Twittys Creek to Pamplin Rebuild	115	Dec-20	VA
Line #112 Fudge Hollow to Low Moor Rebuild	138	Dec-20	VA
Line #231 Landstown to Thrasher Rebuild	230	Dec-20	VA
Line #101 Mackeys to Crewswell Rebuild	115	Dec-20	NC
Buttermilk 230 kV Delivery	230	Dec-20	VA
Perimeter 230 kV DP – NOVEC	230	Dec-20	VA
Evergreen Mills 230 kV Delivery	230	May-21	VA
Clover Substation – New 500 kV STATCOM	500	May-21	VA
Ladysmith 2nd 500-230 kV transformer	500/230	May-21	VA
Farmwell – 230 kV Delivery	230	May-21	VA
Line #274 Pleasant View to Beaumeade Rebuild	230	Jun-21	VA
Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230 kV Lines and New 230 kV Substation	230	Jul-21	VA
Rawlings Switching Station New 500 kV STATCOM	500	Sep-21	VA
Line #65 Norris Bridge Rebuild	115	Dec-21	VA
Line #49 New Road to Middleburg – Rebuild	115	Dec-21	VA
Line #127 Buggs Island to Plywood Rebuild	115	Dec-21	VA
Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Partial Rebuild	115	Dec-21	VA
Line #120 Dozier-Thompson Corner Partial Rebuild	115	Dec-21	VA
New Switching Station to Retire Line #139 Everetts to Windsor DP	115	Dec-21	NC
Line #2008 Partial Rebuild and Line #156 Retirement	115; 230	Dec-21	VA
Line #550 Mt. Storm to Valley Rebuild	500	Dec-21	WV– VA
Mt. Storm - I/S GIS	500	May-22	WV
Line #43 Staunton to Harrisonburg – Rebuild	115	Jun-22	VA
Line #247 Suffolk Swamp Rebuild	230	Dec-22	VA– NC
Line #2175 Idylwood to Tyson's – New 230 kV Line	230	Dec-22	VA

Note: see Appendix 3D for North Carolina line capacity levels.

DOMINION ENERGY VIRGINIA'S
INTEGRATED DISTRIBUTION PLANNING WHITE PAPER

1.0 INTRODUCTION

A major trend over the last 10-plus year period in the electric power industry has been the development of renewable generation, especially photovoltaic ("PV") and wind generation. Since 2008, wind generation capacity in the U.S. has experienced a compound annual growth rate ("CAGR") of approximately 19%, while PV has seen an approximately 61% CAGR. The Company expects these renewable energy growth trends to continue as customers demand more carbon free forms of energy. An important sub-trend is the growth of distributed energy resources ("DERs")—resources connected to the distribution system. According to the Energy Information Administration ("EIA"), the growth in U.S. of clean DERs (*e.g.*, hydroelectric, wind, PV) from 2009 through 2017 has been approximately 23%. The Company has experienced an approximately 43% DER growth rate on its system during that same timeframe, primarily in the form of PV systems. A subset of the EIA data for non-net metered PV DER experienced a CAGR of approximately 48% nationwide. This trend is expected to continue given the expected efficiency improvements and cost reductions in PV technology.

Along with this increase in distributed generation resources interconnected to the distribution system, other trends continue to develop, including the addition of high-energy electric vehicle charging, the adoption of energy storage, and a change in customer energy usage patterns driven by AMI-enabled time-varying rates. Utility planners must continue to adapt their skills, tools, and processes to integrate these new challenges into the electric energy infrastructure planning landscape. No longer is grid planning based only on load growth and the static impact during peak usage periods on the distribution grid. Now, planners must also anticipate new supply-side and demand-side resources in the form of DERs, understand the dynamic impact to the grid, and examine how DERs can provide non-traditional solutions to traditional grid challenges, such as line overloads and voltage deviations. To that end, historical distribution planning methods must change to an integrated distribution planning process.

The Company defines integrated distribution planning ("IDP") as a process to address the capacity, reliability, and DER integration needs of the distribution grid using traditional solutions as well as new solutions offered by customer-owned DER and other non-traditional technologies. IDP also accounts for uncertainties introduced by the dynamic nature of variables impacting grid operation, shifting results and associated decisions from deterministic to probabilistic outcomes. True IDP requires changes in planner's skills, technologies and tools used, and processes. Throughout, trained professionals are vital to fully leverage the technologies and optimize the processes and emerging tool sets. Technologies and communications systems that provide visibility into the distribution grid to the customer premises level are foundational to enabling integrated distribution planning. Processes and tools must then be developed to incorporate the data gathered, including advanced distribution modeling and analysis tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on different parts of the distribution system.

This white paper provides an overview of the Company's current planning process, highlights the limitations of the current process, and sets forth the initial steps the Company plans to take to transition toward integrated distribution planning.

2.0 CURRENT DISTRIBUTION PLANNING

The Company's current distribution planning occurs through three distinct processes: (i) distribution capacity planning; (ii) distribution reliability planning; and (iii) DER interconnection. Together, these efforts result in a plan designed to address customer needs to ensure safe, reliable, and cost-effective electric service using traditional utility solutions.

2.1 Current Distribution Capacity Planning

2.1.a Overview of the Current Capacity Planning Process

The purpose of distribution capacity planning is to evaluate grid utilization during seasonal peak loading conditions based on projected load growth, identifying any necessary improvements to the distribution system needed to satisfy thermal and voltage criteria as the demands placed on the distribution infrastructure change over time. Figure 2.1 provides an overview of the current process.

Figure 2.1: Current Distribution Planning Process

	Inputs	Modeling & Analysis	Alternatives Evaluation	Outputs
CAPACITY PLANNING	• Historical seasonal peak loads • Historical and projected growth • Interval data at T to D transition point only • Utility scale DER contribution removed • No visibility of net metering DER • Steady state load and voltage criteria	• Static analysis for peak loading • Manual feeder-by-feeder analysis • Only steady state system analysis performed • DER not included in model • Loading allocated based on modeling assumptions	• Traditional mitigation alternatives: equipment upgrades/additions • Solutions optimized for cost / load growth and system impact	**Multi-year Work Plan**

2.1.b Current Distribution Load Growth Forecasting

The historical distribution capacity planning process centers around assessing current and anticipated constraints on the distribution grid associated with forecasted seasonal peak load conditions. Therefore, the Company annually develops a six-year summer and winter peak load forecast (for the next 5 years and for the 10th year into the future) for each of the approximately 1,800 feeders currently on the Company's system. These forecasts are assembled based on historical data measured at the feeder head (*i.e.*, the point of demarcation between the transmission and distribution systems) and information acquired through discussions with (and formal requests from) current and future customers. Examples of the information used to develop the forecast are historical load growth trends, planned new housing developments, new high-rise buildings, information regarding data center expansions or additions and commercial and industrial development. This information is then used by the Company's distribution planners to update feeder-level load growth projections. Generally, load growth forecasting is not location specific beyond information regarding block load additions that are known in the short term (*e.g.*, a new big box retail store under construction). Of note, there are no inputs related to customer-level usage patterns or DER and emerging technology penetration growth included in this current forecasting process. Traditional static capacity planning focuses on the system's summer and winter peak conditions, studying the traditional "worst case scenarios." Based on this focus, the current load growth forecasting utilizes only peak customer demand and removes DER to ensure the grid will remain reliable under these conditions.

2.1.c Current Distribution Capacity Planning

The current distribution capacity planning process is conducted on an annual basis and evaluates the adequacies of each of the Company's distribution feeders under the forecasted annual summer and winter peak load conditions over the planning period. The primary measurable input to this is currently limited to data collected at the feeder head. This evaluation is performed under normal operations and first contingency (N-1) conditions. Normal operations are defined as seasonal peak load conditions under normal distribution system configuration. First contingency (N-1) conditions are defined as situations that simulate the loss of a single distribution substation transformer during seasonal peak loading conditions.

Under both normal and first contingency conditions, distribution planners use computer modeling tools to identify if and when violations of capacity planning criteria are projected to occur on a particular feeder, feeder component or distribution substation transformer. Using feeder head data, the model approximates the expected loading along a feeder and all of its components based on engineering assumptions. The typical engineering limitations examined are conductor, transformer or equipment thermal limits (ampacity), and high or low voltage.

Once the timing and type of violations are determined on any given feeder component or substation transformer, the next step is to identify what grid mitigation solutions are necessary to correct the violation. Mitigation solutions may include re-configuration of the feeder, the addition or replacement of equipment (*e.g.*, capacitors, transformers, protection devices), replacing conductor with larger conductor (*i.e.*, reconductoring), or adding an entirely new substation or feeder. These all are considered traditional solutions.

2.2 Current Distribution Reliability Planning

2.2.a Overview of the Current Reliability Planning Process

The purpose of reliability planning is to identify causes of service interruptions and risks to the grid, and to develop cost-effective and prudent solutions to improve overall grid performance and customer experience. Figure 2.2 provides an overview of the current process.

Figure 2.2: Current Distribution Reliability Planning

	Inputs	Modeling & Analysis	Alternatives Evaluation	Outputs
RELIABILITY PLANNING	• Historical performance data focused on blue sky days • Multiple levels of analysis o System metrics o Feeder level o Responsive to specific customers	• Root cause analysis • Manual feeder-by-feeder analysis • Specific asset health testing and assessment • Manual mitigation modeling to predict improvement	• Traditional mitigation alternatives • Solutions optimized for cost, reliability and risk	Annual Work Plan

2.2.b Current Distribution Reliability Planning

Reliability planning is based on data analytics of service outage information. The Company maintains a historical database of service outages that includes the when, where, and why associated with each service outage generated by the Company's outage management system ("OMS"). This data is analyzed to identify areas of the distribution system that have exhibited reliability performance issues, including root causes. For repeat outages on the same feeder or feeder section, the Company evaluates the cause to determine if there is a pattern to these outages. Depending on this pattern, the Company can devise mitigation measures to improve feeder performance. If, for example, lightning strikes have caused excessive amounts of outages in a specific area, the Company can mitigate future outages through the use of additional surge arresters for lightning protection, or investigate if grounding is within its operating specifications and physically improve the grounding system if it does not meet the operating specification. Another example of mitigation measures is to recondition poorly performing feeders by repairing defects and restoring the feeder to current construction standards.

This data examination process is conducted by the Company on a continual basis. The findings are gathered and used to support reliability improvement investment decisions.

2.3 DER Generation Interconnection Process

The Company's DER generation interconnection process requires the customer to request to export energy directly onto the distribution grid. Which interconnection process DER customers must follow depends upon (i) whether the DER customer opts to sell its output wholesale to PJM Interconnection, LLC ("PJM") or to the Company; and (ii) whether the DER customer elects to interconnect directly to distribution infrastructure as a small electrical generator or behind the customer's meter via net energy metering.

DER requests involving wholesale market participation requests are submitted to PJM. PJM administers the processing of the interconnection requests to its queue and coordinates the interconnection study process, as applicable, with the Company. The Company administers all other generator interconnection requests under the appropriate state jurisdictional procedures.

2.3.a Small Electrical Generator Interconnection Process

The interconnection process for small electric generators is administered in accordance with the Commission's Regulations Governing Interconnection of Small Electrical Generators, 20 VAC 5-314-10 *et seq.* The Commission initiated a rulemaking proceeding in September 2018 to possibly revise these regulations, Case No. PUR-2018-00107. The proceeding remains pending. A high level view of this current interconnect process is provided in Figure 2.3.a.

Figure 2.3.a: Overview of DER Small Electrical Generator Interconnection Process

	Inputs	Modeling & Analysis	Alternatives Evaluation	Outputs
INTER-CONNECTION PLANNING	• Customer initiated requests • Mandated queue procedures • Location specific load and grid data • Customer equipment specifications	• Static analysis for specific loading and DER output scenarios • Manual analysis for interaction with other DER	• Traditional mitigation alternatives: equipment upgrades/additions	**Interconnection Agreement Execution**

The Company must study the interconnection of all generation that operates in parallel with the electric grid to identify if grid modifications are needed to accommodate the proposed interconnection while maintaining safe and reliable operation of the grid for all customers. Under the governing standards, the interconnection customer submitting the request is responsible for the costs to study the impact of the DER on the distribution system and for the costs to modify the grid to accommodate the proposed generation.

The Company's technical study process for utility-scale solar systems ensures that the output of the renewable generator does not result in thermal overload conditions or voltage deviations outside of an acceptable bandwidth on any feeder component or substation transformer to which the PV generator interconnects. The fault current contribution of the generator is also analyzed for its potential impact to the grid. The study is a static analysis based on the ability of the PV system to operate at full-rated output during daylight hours, with secondary consideration of inverter-based DERs to provide grid support for this injection or absorption of reactive power. Based on current grid visibility and control limitations, the Company has asked a small percentage of the generators to apply a fixed power factor setting, other than unity, for voltage support as a secondary measure.

DER interconnection requests have grown significantly over the past several years. Currently there are 28 utility-scale solar generation sites totaling 275 MW interconnected to the Company's electric distribution system in Virginia. As of August 1, 2019, there are 22 interconnection requests totaling 225 MW with executed interconnection agreements that are in the construction process, and 114 requests totaling 1,584 MW that are at some level of evaluation under the state jurisdictional procedures.

2.3.b Net Energy Metering Interconnection Process

If a renewable DER is proposing to offset a portion of a customer's own load, the customer may be eligible to apply for net energy metering. Net metering is administered in accordance with the Commission's Regulations Governing Net Energy Metering, 20 VAC 5-315-10 *et seq*. The Commission initiated a proceeding in August 2019 to amend these regulations consistent with new legislation, Case No. PUR-2019-00119. The proceeding remains pending.

The technical study process for net energy metering is currently a more simplified approach than the process for small electrical generators given the much smaller DER system size. The simplified approach ensures that the interconnecting system does not create an adverse thermal or voltage issue. Any necessary system upgrades (if any) are included in the Company's current base rate structure.

The Company has seen a dramatic growth rate in net metering interconnections, with a clear trend showing concentrated growth in certain geographic areas. Figures 2.3.b.1 and 2.3.b.2 show the total number of net metering customers for the top 10 office locations, as well as the growth in net metering by office since January 1, 2018.

Figure 2.3.b.1: Local Office Totals

Office Name	Cust	MW
Chalottesville	835	8.9
Alexandria	642	4.7
Blue Ridge	385	4.4
Richmond	352	3.1
Leesburg	269	2.7
Fairfax	324	2.3
Norfolk	100	2.1
Midlothian	201	2.1
East Richmond	258	2.0
Springfield	284	1.8
All Others	2,427	20.0
Total	**6,077**	**53.9**

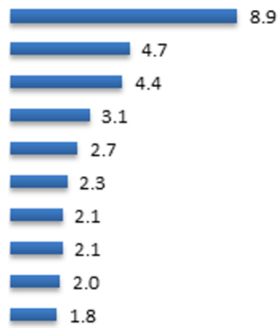
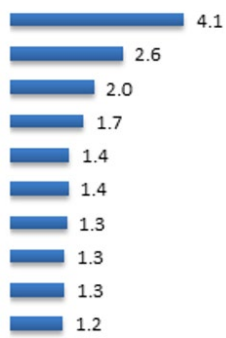


Figure 2.3.b.2: Local Office Growth Since January 1, 2018

Office Name	Cust	MW
Chalottesville	407	4.1
Blue Ridge	196	2.6
Alexandria	282	2.0
Norfolk	60	1.7
Midlothian	131	1.4
Fairfax	184	1.4
Springfield	194	1.3
Richmond	161	1.3
Gloucester	66	1.3
Peninsula	190	1.2
All Others	1,480	11.9
Total	**3,351**	**30.5**



3.0 LIMITATIONS OF CURRENT PLANNING PROCESS

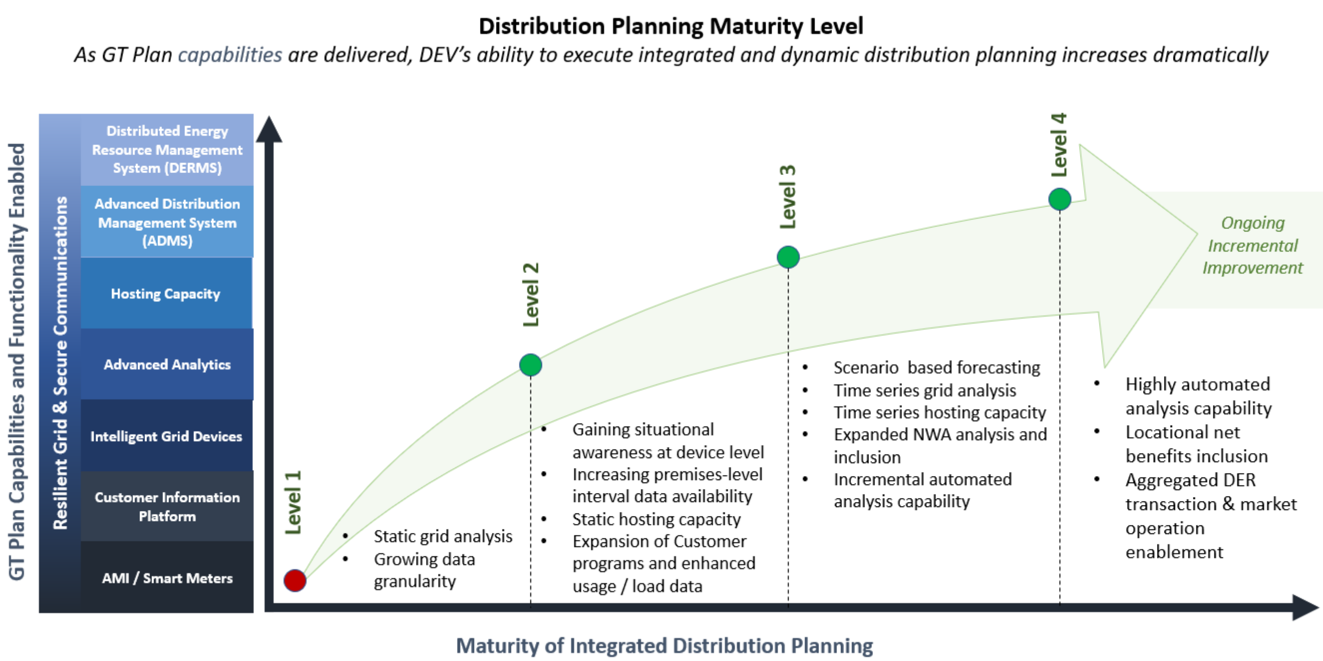
Current distribution planning methodologies and processes have been in place for decades and were designed to identify the most cost-effective means of maintaining a safe and reliable distribution grid. These practices have been effective in a world of centralized large-scale generation and one-way power flows. In that light, modeling and analyzing distribution grid limitations for discrete conditions (seasonal peak conditions) have worked effectively as a manual process. In the new paradigm of increasing DERs and other emerging end-use technologies creating a more dynamic distribution grid with bi-directional and constantly changing power flows, awareness of temporal and spatial growth and operating characteristics are necessary. Modeling the distribution grid under this necessity can no longer be done using traditional techniques. Future modeling and analysis requires the development of advanced and automated tools that are capable of using significantly more granular data and providing outputs on a much broader time scale of probabilistic distribution grid limitations. Limitations of grid visibility beyond the feeder head present uncertainty in determining non-peak characteristics of how the grid is functioning. Additionally, the ability to confidently leverage non-wires alternatives as a prudent alternative to traditional grid solutions requires a level of situational awareness, communications infrastructure, and control capabilities that do not currently exist on the Company's distribution grid.

The historical process of determining distribution system need only during forecasted seasonal peak conditions, with grid visibility limited primarily to the feeder head, is approaching obsolescence. Under the current distribution capacity planning process, anticipated growth in DERs and emerging technology are not able to be addressed. Further, the current process does not assess multiple potential scenarios of adoption rates of DER and emerging technologies. Changing distribution grid load flows along with temporal and spatial growth patterns and operating characteristics at times other than peak hours are, and will continue, to change the dynamics (*i.e.*, the load shape) of the distribution grid moving forward. Limitations of grid visibility beyond the feeder head present uncertainty in determining non-peak characteristics of how the grid is functioning.

4.0 FUTURE INTEGRATED DISTRIBUTION PLANNING PROCESS

The Company plans to implement an integrated distribution planning ("IDP") process that will evolve the current planning processes to adapt to the increasing proliferation of customer-owned DERs and other changes relevant to the modern grid. True IDP will require changes to people's skills, the technologies and tools they use, and processes for performing planning activities. The sections below describe the enhancements the Company plans to make within each of these categories. Figure 4.0 provides a chart showing the evolution of integrated distribution planning over time as enabling technologies are deployed.

Figure 4.0: IDP Evolution



4.1 People

As an initial step towards integrated distribution planning, the Company is centralizing the modeling and analysis activities for capacity planning, reliability planning, and DER interconnection as an integrated functional organization. The Company will continue to evaluate its organizational structure as integrated distribution planning matures in support of the enhancements described below.

4.2 Technologies

IDP is highly dependent on having highly granular and spatial visibility of existing grid conditions. The Company has a plan to transform its distribution grid (the "Grid Transformation Plan" or "GT Plan") to adapt to the fundamental changes to the energy industry described above and to meet its customers' needs and expectations. Many of these proposed investments are foundational to IDP, including investments in advanced metering infrastructure ("AMI"); a self-healing grid, including intelligent grid device and an advanced distribution management system ("ADMS") with system capabilities for distributed energy resources management ("DERMS"); and Advanced Analytics. Advanced Analytics can suitably model the behavior of the entire distribution network including the renewable resources. These applications can analyze weather patterns along with past generation profiles and forecast the generation that will be available from the DER. Advanced Analytics will highlight opportunities for non-wires alternatives to be evaluated. Also vital are secure communications between the field devices and the back office systems. The Company's executive summary of the Grid Transformation Plan (the "Plan Document") provides additional information on these proposed investments.

4.3 Processes and Tools

IDP requires advanced distribution modeling and analysis capabilities that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution system. The distribution grid needs to be analyzed at a wide range of load conditions, rather than at just peak load periods. The ability to successfully perform time series modeling analysis ("TSA") of the distribution grid is heavily reliant on a highly granular visibility of existing load and DER characteristics. Finally, given the uncertainty associated with the size and location of DER growth, probabilistic or stochastic analytical techniques will be required to evaluate the robustness of the distribution grid from the feeder head to the feeder edge.

The Company plans to implement the following process-related enhancements to its distribution planning process to move toward IDP. These enhancements are illustrated in Figure 4.3 and discussed in more detail below.

Figure 4.3: Enhanced Distribution Planning Process

	Inputs	Modeling & Analysis	Alternatives Evaluation	Final Plan
Integrated Distribution Planning	• Feeder load forecast scenarios (time series) • DER & emerging tech growth forecast scenarios • Additional planning inputs: (hosting capacity, AMI & IGD load and voltage data, all DER output data, feeder characteristics (EAM data), performance metrics, etc. • Engineering model build and framework for scenario based analysis • Network assessment (Static and Time Series Analysis) • Reliability assessment • Planning criteria	• Reliance on engineering models based on a high level of data granularity • Automated generation of time series analysis and holistic solutions • Inclusion of Non-Wire Alternatives (Storage, Advanced Inverter Functionality, DSM, etc.) • Inclusion of locational value of resources	• Traditional Grid Solutions • DER & DSM Opportunities • Grid Transformation Projects • Optimization of alternatives over time	**10 Year Distribution Forecast and Investment Roadmap** **Transmission and Generation System Planning Impacts**

4.3.a Process Enhancement 1 – Comprehensive Feeder Level Forecasting

Long-term (*i.e.*, minimum 10 year) demand growth forecasts will be refined for each individual distribution feeder and include not only the amount but also the type of future DER capacity. Utility-scale, commercial, and residential net metering-scale sites will be forecasted annually. Unlike conventional demand forecasting methods, however, these forecasts will be more granular in that they will be developed down to the customer site whenever possible and will cover all hours in a year rather than just peak demand hours. The Company initially plans to develop these forecasts utilizing data obtained from its customers currently served with AMI meters and/or intelligent grid device data, where available. Until full deployment of AMI has been achieved, the Company will develop hourly demand assumptions for its monthly-metered customers using relationships obtained from historic AMI hourly load shapes and monthly customer billing records. Comprehensive feeder level forecasts will allow the Company to simulate power flow scenarios within a planning period. This ability is critically important as the Company expects more active management of grid stability to be necessary during low demand conditions that are coupled with high DER output.

For example, during the month of April, a residential customer's electricity demand at any hour is typically low (less than 5 kW). If that same customer has a solar PV system rated at 10 kW installed at their premise, it is quite likely that for many hours during April, the supply from that customer's premise will exceed their demand and that excess power will flow onto the distribution grid. This situation could cause a localized increase in distribution voltage levels that exceed rated standards. This voltage violation could result in damage to the Company's equipment or damage to appliances of other customers that are on the same feeder. As DERs continue to grow on the Company's system, phenomena such as this can spread to all areas of the distribution feeders and even onto the transmission grid. This undesirable phenomenon is not related to overall system DER penetration but rather is specific to locational concentrations of DER penetration. The magnitude of the challenge grows as this scenario occurs at grid locations with limited host capacity available.

4.3.b Process Enhancement 2 – Hosting Capacity Analysis

The Company will also study the DER hosting capacity on every distribution feeder in order to determine the strength of the distribution system during varying degrees of DER penetration and solar irradiance levels for every hour of the day. This analysis when overlaid with the Company's DER forecast can determine the year when a specific feeder becomes at risk for exceeding feeder design specifications (both thermal and voltage parameters), and will enable the use of active power management of DER as an alternative to traditional grid upgrades. The forecasts described above will be updated annually and will form the base or expected cases for subsequent distribution analysis and planning activities. Until such time as a proper stochastic algorithm can be developed, the Company will also prepare annually, high and low DER growth forecasts for each feeder to support the scenario analysis described below. This transition requires highly manual analysis until such time as automated analytical systems are developed and validated.

If the GT Plan investments are approved by the Commission, the Company plans to publish initial hosting capacity maps for both utility-scale and net metering DER by the end of 2020. As additional grid technologies and smart meters are deployed and grid operation capabilities increase, the hosting capacity maps will become more dynamic and support opportunities to reduce interconnection costs when DER output can be informed and adjusted to avoid grid limitations through a DERMS.

4.3.c Process Enhancement 3 – Multi-Hour Capacity Planning Analysis

Consistent with conventional distribution capacity planning analysis, each feeder will be assessed under seasonal peak demand periods using the forecast for demand and DER growth described above. Also, like current state, the analysis will evaluate the distribution grid for violations with respect to loading and voltage. Beyond current state, the distribution grid will also be examined at conditions other than peak demand periods. At a minimum, the Company will evaluate the distribution grid under peak demand and minimum demand conditions for each month of the planning period. The frequency and the study time window of these studies will increase as advanced modeling techniques are refined. As discussed further below, the Company is investigating, with industry peers and research entities, the development of the necessary engineering tools and systems that can perform this analysis on a time series (*i.e.*, 8760) basis so that, when appropriate, each hour of the planning period can be examined in an automated fashion. This will ensure the Company examines all load and generation conditions associated with the base forecast for demand and DER growth. These new tools and systems will result in a more thorough analysis of each feeder under various load and generation conditions that is more representative of two-way power flows caused by DERs. Notably, specific GT Plan investments in intelligent grid devices and smart meters that gather this highly granular data are necessary to support robust analyses with greatly reduced uncertainty.

4.3.d Process Enhancement 4 – DER Scenario Analysis

The key uncertainties associated with future DER growth is with respect to rate of growth and location. As such, the enhanced distribution planning analysis will also include scenario analysis that utilizes the high and low DER growth forecasts identified above. Again, the Company will analyze each feeder for violations with respect to loading and voltage under monthly peak and low demand conditions using both the high and low DER growth rate forecasts.

4.3.e Process Enhancement 5 – Non-Wires Alternatives Analysis

In addition to traditional distribution grid solution approaches such as re-conductoring or equipment upgrades, the Company will also assess non-wires alternatives to address violations that may surface in the distribution grid analysis process. New mitigation options such as utilizing customer-owned advanced inverter capabilities, battery energy storage systems, micro-grids, or demand response will be evaluated along with traditional solutions to assure that the optimal solutions for the Company and customers are prudently implemented.

5.0 PROOF OF CONCEPT ANALYSIS AND RESULTS

The ultimate objective of the Company's IDP process is to develop a prudent distribution investments roadmap based on load growth, reliability needs, DER growth, new technology adoptions, and other changes on the distribution system over the planning horizon. To that end, the Company engaged DNV GL Digital Solutions ("DNV GL") to develop a proof of concept. The DNV GL analysis focused on the process enhancements described above, namely multi-hour capacity planning analysis, DER scenario analysis, and non-wires alternatives analysis.

DNV GL developed an analytical process using Synergi Electric software, which provides tools that are capable of automating the grid analysis. DNV GL then tested the software using three demonstration feeders identified by the Company. The analytical process involved running a multi-year time series analysis ("TSA"), identifying times where technical violations may occur due to load growth or due to DER operation, designing appropriate mitigations and evaluating the hosting capacity of the system for different capacities of DER.

The Company intends to continue to work with DNV GL as the Company implements the process enhancements described above. Notably, the DNV GL process integrates the Company's current capacity planning and DER interconnection processes, but does not incorporate the current reliability planning processes. As recognized industry-wide, incorporating the reliability planning component is the area of analysis having the greatest complexity . The Company will continue to work toward complete integration of its distribution planning process.

DNV GL produced a report providing its analyses and results. The report is Attachment 1 to this white paper.

6.0 CAPABILITIES ENABLED BY INTEGRATED DISTRIBUTION PLANNING

The evolution of IDP over time will enable capabilities and benefits for the Company and customers not available today. For instance, with people, technologies, and processes described above, locational net benefits could be identified and published, an expanding portfolio of non-wires alternatives can be developed and utilized, and lower DER integration costs can result. With proper policy and regulatory support, IDP also enables aggregated DER transactions.

7.0 GENERATION, TRANSMISSION, AND DISTRIBUTION INTEGRATION ASSESSMENT

Currently, power system analysis is performed separately for generation, transmission and distribution systems. With higher overall system penetration levels of DERs expected, the one-way flow of the Company's distribution system is being significantly altered and will impact the generation, transmission, and distribution systems. Therefore, the Company (along with the electric utility industry) needs to continue its development of new methods and tools to properly integrate the overall power system. For example, as DERs continue to grow within the Company's service territory and emerging technologies take hold, customer load shapes will change. This change in load shape will not only impact the distribution grid but also the transmission and generation systems as well. Power flows along the transmission system will change (and could even reverse) and traditional generators will be dispatched in a manner that may be quite different than has been done in the past in order to accommodate these new customer demands. Thus, it is important that the Company understand how customer energy use is changing and how those changes are impacting the entire electric network, from distribution, to transmission and generation.

Importantly, the shift to integrated distribution planning is a process that will take time, as illustrated in Figure 4.0. The Virginia Code now requires that the Company's total-system integrated resource plans evaluate long-term electric distribution grid planning. Va. Code § 56-599 B 10. The Company thus intends to continue to report on its progress toward IDP in future integrated resource plans. The Company plans to include IDP as part of the stakeholder processes used for the Company's GT Plans and integrated resource plans.

NCUC Docket No. E-100, Sub 165

2020 IRP

ADDENDUM 1

Renewable Energy and Energy Efficiency Portfolio Standard Compliance Plan

NCUC Docket No. E-100, Sub 165

2020 IRP

ADDENDUM 1

Renewable Energy and Energy Efficiency Portfolio Standard Compliance Plan

VIRGINIA ELECTRIC AND POWER COMPANY
2020 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 Energy North Carolina ("DENC" 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 (2020) and immediately subsequent two calendar years (2021-2022) (the "Planning Period"). The Company also presents REPS compliance information for Town of Windsor ("Windsor") during the Planning Period.[1]

The Company's 2020 REPS Compliance Report, to be filed in August 2020, will indicate that the Company and Windsor have satisfied all 2019 REPS compliance obligations.

1.1 RENEWABLE ENERGY REQUIREMENTS

Figures 1.1.1 and 1.1.2 summarize the Company's North Carolina REPS goals and Virginia's Renewable Energy Portfolio Standard ("RPS") goals for each year of the Planning Period. Figure 1.1.3 summarizes Windsor's North Carolina REPS goals.

Figure 1.1.1 2020-2022 COMPANY'S NC REPS COMPLIANCE GOALS

	2020	2021	2022
NC Total REPS Obligation %	10.0%	12.5%	12.5%
NC Solar Set-Aside Target %	0.20%	0.20%	0.20%
NC Total Swine Set-Aside %	0.07%	0.07%	0.14%
Projected Poultry Set-Aside %	3.19% of 700,000	3.19% of 900,000	3.19% of 900,000

Figure 1.1.2 2020-2022 COMPANY'S VA RPS COMPLIANCE GOALS[1]

	2020	2021	2022
VA Total RPS Obligation %	7.0%	14.0%	17.0%

[1]The 2020 RPS goals are a percentage of the amount of electricity sold in 2007 (the "base year"), minus the average annual percentage of nuclear generators between 2004 and 2006. In 2021 and beyond, the RPS goals are a percentage of the electricity sold during the previous calendar year.

Figure 1.1.3 2020-2022 TOWN OF WINDSOR'S NC REPS COMPLIANCE GOALS

	2020	2021	2022
NC Total REPS Obligation %	10.0%	10.0%	10.0%
NC Solar Set-Aside Target %	0.20%	0.20%	0.20%
NC Total Swine Set-Aside %	0.07%	0.07%	0.14%
Projected Poultry Set-Aside %	0.04% of 700,000	0.04% of 900,000	0.04% of 900,000

[1]Town of Windsor is a wholesale customer of the Company, for which DENC provides REPS compliance services.

1.2 COMPLIANCE PLAN

In accordance with Rule R8-67(b)(1)(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.

The Company

During the Planning Period, the Company 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.

Figure 1.2.1 summarizes the Company's REPS compliance requirements and strategy for the Planning Period.

Figure 1.2.1 2020-2022 COMPANY'S REPS COMPLIANCE PLAN SUMMARY

	2020	2021	2022
Baseline Sales Forecast (MWh)	4,472,000	4,489,000	4,482,000
NC Total REPS Obligation %	10.0%	12.5%	12.5%
Total REPS Obligation (MWh)[1]	428,070	559,000	561,125
NC Solar Set-Aside Target %	0.20%	0.20%	0.20%
Total Solar Set-Aside (MWh)[1]	8,562	8,944	8,978
NC Total Swine Set-Aside %	0.07%	0.07%	0.14%
Total Swine Set-Aside (MWh)[1]	2,997	3,131	6,285
Projected Poultry Set-Aside %	3.19%	3.19%	3.19%
Total Poultry Set-Aside (MWh)[2]	22,312	28,686	28,686
General Requirement (net of Solar, Swine and Poultry) (MWh)	394,199	518,239	517,176
Projected Energy Efficiency (MWh)[3]	30,948	30,948	30,948
Projected Company Generated Renewables (MWh)[4]	92,612	223,505	256,355

Notes: (1) 2020 targets are based on actual 2019 retail sales of 4,280,697 MWh. 2021-2022 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) Targets are based on the average of 2016-2018 load share ratio. (3) For REPS reporting and compliance purpose, DENC will rely upon actual EE savings achieved by North Carolina customers. (4) Company Generated Renewables (MWh) are the estimated North Carolina jurisdictional allocation of the Company's solar and biomass generation.

[2] On December 16, 2019, the Commission issued an Order reducing the swine waste set-aside requirement to 0.04% for the electric public utilities and delaying the swine waste set-aside requirement for municipalities. The Commission also modified the poultry waste set-aside aggregate requirement to 500,000 MWh. *Order Modifying the Swine and Poultry Waste Set-Aside Requirement and Providing Other Relief,* Docket No. E-100, Sub 113 (December 16, 2019) ("2019 Delay Order").

[3] For planning purposes, the Company notes that it 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 the Company to achieve up to 100% REPS general obligation and set-aside compliance using out-of-state RECs).

As shown in Figure 1.2.1, the Company's REPS 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 energy efficiency savings, is an amount equivalent to ten percent (10%) of its prior year retail sales in compliance year 2020, and twelve and a half percent (12.5%) in 2021 and 2022 ("Total Obligation").[4]

The Town of Windsor

Planned REPS compliance for Windsor during the Planning Period is outlined in Figure 1.2.2

Figure 1.2.2 2020-2022 TOWN OF WINDSOR'S REPS COMPLIANCE PLAN SUMMARY

	2020	2021	2022
Baseline Sales Forecast (MWh)	48,100	48,600	49,100
NC Total REPS Obligation %	10%	10.0%	10.0%
Total REPS Obligation (MWh)[1]	4,783	4,810	4,860
NC Solar Set-Aside Target %	0.20%	0.20%	0.20%
Total Solar Set-Aside (MWh)[1]	96	97	98
NC Total Swine Set-Aside %	0.07%	0.07%	0.14%
Total Swine Set-Aside (MWh)	34	34	69
Projected Poultry Set-Aside %	0.04%	0.04%	0.04%
Total Poultry Set-Aside (MWh)[2]	254	327	327
General Requirement (net of Solar, Swine and Poultry) (MWh)	4,399	4,352	4,366

Notes: (1) 2020 targets are based on actual 2019 retail sales of 47,821 MWh reported by Windsor to DENC. 2021-2022 targets are based on forecasts reported by the Windsor to DENC. The total target is a product of the previous year's baseline retail sales and the current year target percentage. (2) Targets are based on the average of 2016-2018 load share ratio.

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 twenty hundredths of one percent (0.20%) of the prior year's total electric power in megawatt-hours ("MWh") sold to retail customers in North Carolina in 2020, 2021 and 2022.

Based on the Company's actual retail sales in 2019, the Solar Set-Aside is 8,288 RECs in 2020. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 8,944 RECs in 2021, and 8,978 RECs in 2022, respectively.

[4] The Company refers to its Total Obligation, net of the Solar, Swine, and Poultry Set-Aside requirements, as its General Requirement ("General Requirement").

The Company's Solar Set-Aside compliance strategy is consistent with DENC's plan from the previous years, as described herein. Specifically, the Company plans to buy unbundled solar RECs. The Company has purchased, or entered into contracts to purchase, solar RECs for DENC's compliance with N.C.G.S. § 62-133.8(d). These contracts will provide enough solar RECs to satisfy the Company's compliance through 2022. The Company has also executed contracts with solar facilities located in North Carolina that will satisfy the in-state portion of the Windsor's compliance requirements for 2020 through 2022. The Company 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 DENC's and Windsor's solar set-aside requirements during the Planning Period.

Swine Waste Set-Aside

Pursuant to N.C.G.S. § 62-133.8(e) and the 2019 Delay Order, for calendar years 2020 and 2021, at least seven hundredths of one percent (0.07%), for calendar year 2022 through 2024, fourteen hundredths of one percent (0.14%) and for 2025 and thereafter at least 20 hundredths of one percent (0.20%) 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. The Company's Swine Set-Aside requirement is 2,901 RECs in 2020, 3,131 RECs in 2021, and 6,285 RECs in 2022.

Both DENC and the Windsor have sufficient swine RECs in NC-RETS to meet the 2020-2022 requirements.

The Company 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 DENC's Swine Set-Aside requirements during the Planning Period. Due to the high default rate with swine waste to energy contracts, the Company intends to contract for RECs above and beyond the initial requirement to increase the probability of maintaining compliance. The Company intends to bank any excess RECs to be used for future compliance.

Poultry Waste Set-Aside

Pursuant to N.C.G.S. § 62-133.8(f) and the 2019 Delay Order, for calendar year 2020, at least 700,000 MWhs, and for 2021 and thereafter, at least 900,000 MWhs 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 3.2 percent, the Company's Poultry Set-Aside is 22,312 RECs in 2020 and 28,686 RECs in 2021 and beyond.

Both DENC and Windsor have sufficient poultry RECs in NC-RETS to meet the 2020-2022 requirements.

The Company continues to evaluate all potential opportunities to purchase both in-state and out-of-state poultry RECs, and will continue to make all reasonable efforts to satisfy DENC's Poultry Set-Aside requirements during the Planning Period. Due to the high default rate with animal waste to energy contracts, the Company intends to contract for RECs above and beyond the initial requirement to increase the probability of maintaining compliance. The Company intends to bank any excess RECs to be used for future compliance.

General REPS Requirements Net of Solar, Swine and Poultry

Pursuant to N.C.G.S. § 62-133.8(d), the Company is required to comply with its Total Obligation in the Planning Period by submitting for retirement a total volume of RECs equivalent to ten percent (10%) in 2020, and twelve and a half percent (12.5%) in 2021 and 2022. This equates to 414,400 RECs in 2020, and approximately 560,000 RECs in 2021 and beyond. This General Requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is 380,899 RECs in 2020 and estimated to be approximately 520,000 RECs in 2021 and beyond. The 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 in-state and out-of-state RECs; and using company-generated new renewable energy resources. For Windsor, the Company plans to comply with the General Requirement using its Southeastern Power Administration ("SEPA") allocation of hydroelectric RECs, in-state biomass RECs, and out-of-state biomass RECs.

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.

Company-generated new renewable energy includes generation 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, which commenced commercial operations in 2013. The Company is currently selling the RECs generated at these biomass facilities in PJM Tier 1 markets at a significant premium to the out-of-state general RECs the Company is purchasing for compliance. Company-generated new renewable energy also includes generation from operational and planned Company-owned solar facilities in Virginia and North Carolina. The Company is selling the solar RECs generated at these facilities in the PJM markets at a substantial premium to the in-state and out-of-state solar RECs the Company is purchasing for REPS compliance.[5]

1.3 REC CONTRACTS

In accordance with Rule R8-67(b)(1)(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, hydro, poultry waste, swine 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 the key terms (volume, term, price, current status, and expiration date) of the Company's executed REC purchase contracts.

[5] On April 10, 2014, the Commission approved the Company's Rule R8-66 REPS Facility Registration Statement for VCHEC in Docket No. E-22, Sub 489. The Company will file Rule R8-66 REPS Facility Registration Statements for Altavista, Hopewell and Southampton power stations and for Company-owned solar facilities prior to relying on these facilities for REPS compliance.

Figure 1.3.1 Solar REC Purchase Contract Summary[1]

	Full Term Total Volume	Term	Price / REC	Total Expense	Current Status	Expiration Date
[redacted]	15,000	6	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	729	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	392	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	4	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	4	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	50	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,000	2	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	40	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	24	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1,544	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	664	2	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	331	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	5,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,932	2	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	9,500	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1,057	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	15,000	3	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	15,000	3	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	7,145	3	[redacted]	[redacted]	[redacted]	[redacted]
Total Volume	**84,416**		[redacted]	[redacted]		

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2013-2020 for future compliance purposes. (2) Contracts for Windsor compliance. (3) Contracts for Windsor solar or general REPS compliance.

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Figure 1.3.2 Poultry Waste REC Purchase Contract Summary[1]

	Full Term Total Volume	Term	Price / REC	Total Expense	Current Status	Expiration Date
[redacted]	0	2	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	25,000	2	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	0	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	15,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	55	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	699	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	20,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	4,860	15	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	6,480	15	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	59,400	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1,576	3	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	136,000	10	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	50	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	10,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	40	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	12,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	225,000	15	[redacted]	[redacted]	[redacted]	[redacted]
Total Volume	**516,160**		[redacted]	[redacted]		

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2012-2020 for future compliance purposes. (2) Contract terminated. (3) Contract for Windsor compliance.

CONFIDENTIAL INFORMATION REDACTED

Figure 1.3.3 General REC Purchase Contract Summary[1]

	Full Term Total Volume	Term	Price / REC	Total Expense	Current Status	Expiration Date
[redacted]	30,000	1	[redacted]			
	20,000	1				
	30,000	1				
	1,000	1				
	42,400	1				
	25,600	1				
	35,000	1				
	25,000	1				
	15,000	1				
	64,746	1				
	10,943	5				
	25,000	1				
	25,000	1				
	25,000	1				
	27,587	3				
	50,000	1				
	50,000	1				
	12,265	2				
	50,000	1				
	30,000	1				
	54,459	1				
	50,000	1				
	50,000	1				
	0	20				
	50,000	1				
	25,000	1				

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Figure 1.3.3 General REC Purchase Contract Summary[1] (Continued)

	Full Term Total Volume	Term	Price / REC	Total Expense	Current Status	Expiration Date
[redacted]	50,000	1	[redacted]			
	350,000	2				
	325,000	1				
	75,978	2				
	150,000	1				
	300,000	1				
	300,000	1				
	400,000	1				
	0	1				
	200,000	1				
	200,000	1				
	1,796,716	10				
	180,338	1				
	47,589	2				
	120,000	1				
Total Volume	**5,319,621**		[redacted]			

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2012-2020 for future compliance purposes. (2) Contract for Windsor compliance. (3) Contract terminated.

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Figure 1.3.4 Swine Waste REC Purchase Contract Summary[1]

	Full Term Total Volume	Term	Price / REC	Total Expense	Current Status	Expiration Date
[redacted]	6,480	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	0	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	0	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2,315	5	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	108,500	15	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	0	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	0	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	0	20	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1,000	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1,672	1	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	36,000	10	[redacted]	[redacted]	[redacted]	[redacted]
Total Volume	**155,967**		[redacted]	[redacted]		

Notes: Contract counterparties and prices are confidential. (1) The Company plans to bank any surplus RECs from 2010-2020 for future compliance. (2) Reduced volumes in first year of contract. (3) Price escalates annually. Prices given are for initial year. (4) Contract terminated. (5) Contract for Windsor compliance.

CONFIDENTIAL INFORMATION REDACTED

1.4 ENERGY EFFICIENCY PROGRAMS

In accordance with Rule R8-67(b)(1)(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 North Carolina EE savings to meet the REPS requirements as permitted by law. Figure 1.4.1 lists energy efficiency programs and resulting potential savings projected to be achieved by North Carolina customers. A description of these EE programs can be found in the 2020 EM&V Report filed on May 1, 2020, in Docket No. E-22, Sub 577.

Figure 1.4.1 POTENTIAL SAVINGS (MWh) NORTH CAROLINA ENERGY EFFICIENCY PROGRAMS

	2020	2021	2022
Air Conditioner Cycling Program[1]	0	0	0
Commercial HVAC Upgrade Program[1]	110	110	110
Commercial Lighting Program[1]	2,743	2,743	2,743
Residential Low Income Program[1]	615	615	615
Residential Lighting Program[1]	1,028	1,028	1,028
Non-residential Energy Audit Program[2]	1,386	1,386	1,386
Non-residential Duct Testing and Sealing Program[2]	3,155	3,155	3,155
Residential Home Energy Check-Up Program[2]	791	791	791
Residential Duct Sealing Program[2]	133	133	133
Residential Heat Pump Tune-Up Program[2]	1,208	1,208	1,208
Residential Heat Pump Upgrade Program[2]	297	297	297
Non-residential Heating and Cooling Efficiency Program[3]	540	540	540
Non-residential Lighting Systems and Controls Program[3]	9,687	9,687	9,687
Non-residential Window Film Program[3]	4	4	4
Income and Age Qualifying Home Improvement Program[4]	225	225	225
Small Business Improvement Program[5]	1,732	1,732	1,732
Residential Retail LED Lighting Program (NC Only)[5]	6,913	6,913	6,913
Non-Residential Prescriptive Program[6]	381	381	381
Energy Efficiency Total[7]	**30,948**	**30,948**	**30,948**

Notes: (1) DSM I programs. (2) DSM II programs. (3) DSM III programs. (4) DSM IV programs. (5) DSM V programs. (6) DSM VI program. (7) Potential savings based on initial 2019 EM&V data. The Company is using estimates for the first year of these programs, and will use actual savings in subsequent years. For REPS reporting and compliance purpose, DENC will rely upon actual EE savings achieved by North Carolina customers.

1.5 RETAIL SALES & CUSTOMER ACCOUNTS

In accordance with Rule R8-67(b)(1)(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)	Industrial Sales (MWh)	Total Sales (MWh)
2020 (projected)	1,600,000	766,000	2,106,000	4,472,000
2021 (projected)	1,614,000	778,000	2,097,000	4,489,000
2022 (projected)	1,626,000	798,000	2,058,000	4,482,000

Notes: (1) Excludes the 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
2020 (projected)	105,049	17,206	49	122,304
2021 (projected)	106,146	17,351	49	123,546
2022 (projected)	107,398	17,511	49	124,958

Notes: (1) Customer account totals are year-end forecasts.

Town of Windsor

Figure 1.5.3 summarizes the 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)
2020 (projected)	18,500	20,700	8,900	48,100
2021 (projected)	18,700	20,900	9,000	48,600
2022 (projected)	19,000	21,000	9,100	49,100

Note: (1) Sales are year-end forecasts reported by the Town of Windsor to DENC.

Figure 1.5.4 TOWN OF WINDSOR'S CUSTOMER ACCOUNTS[1]

Year	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
2020 (projected)	1,360	400	1	1,761
2021 (projected)	1,365	405	1	1,771
2022 (projected)	1,370	410	1	1,781

Notes: (1) Customer account totals are year-end forecasts reported by the Town of Windsor to DENC.

1.6 AVOIDED COST RATES

In accordance with Rule R8-67(b)(1)(v), the Company provides the following statement regarding the current and projected avoided cost rates for each year.

For facilities eligible for the Company's avoided cost standard offer contract, see Dominion Energy North Carolina Schedule 19 for currently available energy and capacity rates. Figure 1.6.1 shows the Company's projected avoided energy and capacity rates.

Figure 1.6.1 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from E-100 Sub 158)[1]

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2020	30.83	23.73	0.00
2021	31.13	24.52	0.00
2022	31.14	24.64	51.40

Note: (1) These rates were filed on November 1, 2018 and will likely change in a future compliance filing pursuant to the North Carolina Utilities Commission final order in Docket E-100, Sub 158.

1.7 TOTAL & PROJECTED COSTS

In accordance with Rule R8-67(b)(1)(vi), the Company provides the projected total and incremental costs anticipated to implement REPS Compliance plan for each year of the Planning Period.

The Company

The Company's Planning Period incremental costs to comply with the Solar Set-Aside, Swine Set-Aside, Poultry Set-Aside and General Requirements are presented in Figure 1.7.1 below.

Figure 1.7.1 COMPANY'S REPS COMPLIANCE COST SUMMARY

Type of REC	2020	2021	2022
Solar			
Target (MWh)	8,562	8,944	8,978
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
Swine			
Target (MWh)	2,997	3,131	6,285
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
Poultry			
Target (MWh)	22,312	28,686	28,686
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
General RECs			
Target (MWh)	394,199	518,239	517,176
Less Energy Efficiency[2]	30,948	30,948	30,948
Net Target	363,251	487,291	486,228
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
Administrative Costs[3]	$22,000	$22,000	$22,000
Microgrid Research Project Cost[4]	$564	$564	$564
TOTAL PROJECTED COMPLIANCE COST	***$976,333***	***$1,187,260***	***$1,621,884***

Notes: (1) 2020-2022 projected REC costs are based on market estimates, signed contracts and/or ongoing negotiations. (2) Projected EE savings represents a projected system allocation. (3) Administrative costs include, but are not limited to: NC-RETS fees, broker fees and miscellaneous expenses. (4) As permitted by NCGS § 62-133.8 (h)(1) and (4), DENC has developed a North Carolina Microgrid research and development (R&D) project. The Company is currently evaluating options to modify or decommission the microgrid.

CONFIDENTIAL INFORMATION REDACTED

<u>The Town of Windsor</u>

The Town of Windsor's projected Planning Period REPS costs are expected to consist of the sum of the costs required to comply with the Solar Set-Aside, Swine Set-Aside, Poultry Set-Aside and other General Requirements Figure 1.7.2 outlines Windsor's Compliance Cost Summary from 2020 to 2022.

Figure 1.7.2 TOWN OF WINDSOR'S COMPLIANCE COST SUMMARY

Type of REC	2020	2021	2022
Solar			
Target (MWh)	96	97	98
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
Swine			
Target (MWh)	34	34	69
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
Poultry			
Target (MWh)	254	327	327
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
General RECs			
Target (MWh)	4,399	4,352	4,366
REC Cost ($/MWh)[1]	[redacted]		
Projected Cost			
TOTAL PROJECTED COMPLIANCE COST	**$25,402**	**$30,476**	**$32,247**

Notes: (1) 2020-2022 projected REC costs are based on market estimates, signed contracts and/or ongoing negotiations.

CONFIDENTIAL INFORMATION REDACTED

1.8 ANNUAL COST CAPS

In accordance with Rule R8-67(b)(1)(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 2020	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Actual Year-End Annual Customers (2019)	103,813	18,262	50	122,125
Annual Cost Cap per Customer	$27	$150	$1,000	-
Annual Cost Cap, Total	**$2,802,951**	**$2,739,300**	**$50,000**	**$5,592,251**
Projected Cost of Compliance[1]	***$489,358***	***$478,246***	***$8,729***	***$976,333***

Compliance Year 2021	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers (2020)	105,049	17,206	49	122,304
Annual Cost Cap per Customer	$27	$150	$1,000	-
Annual Cost Cap, Total	**$2,836,323**	**$2,580,900**	**$49,000**	**$5,466,223**
Projected Cost of Compliance[1]	***$616,047***	***$560,570***	***$10,643***	***$1,187,260***

Compliance Year 2022	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers (2021)	106,146	17,351	49	123,546
Annual Cost Cap per Customer	$27	$150	$1,000	-
Annual Cost Cap, Total	**$2,865,942**	**$2,602,650**	**$49,000**	**$5,517,592**
Projected Cost of Compliance[1]	***$842,437***	***$765,043***	***$14,403***	***$1,621,884***

Notes: (1) Projected costs were allocated to the customer classes based on customer percentage of total cost cap.

Figure 1.8.2 provides a comparison of Windsor'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 1.8.2 TOWN OF WINDSOR'S COMPARISON TO ANNUAL CAPS

Compliance Year 2020	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Actual Year-End Annual Customers (2019)	1,355	397	1	1,753
Annual Cost Cap per Customer	$27	$150	$1,000	-
Annual Cost Cap, Total	**$36,693**	**$59,250**	**$1,000**	**$96,943**
Projected Cost of Compliance[1]	***$9,615***	***$15,525***	***$262***	***$25,402***

Compliance Year 2021	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers (2020)	1,360	400	1	1,761
Annual Cost Cap per Customer	$27	$150	$1,000	-
Annual Cost Cap, Total	**$36,720**	**$60,000**	**$1,000**	**$97,720**
Projected Cost of Compliance[1]	***$11,452***	***$18,712***	***$312***	***$30,476***

Compliance Year 2022	Residential Customers[2]	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers (2021)	1,365	405	1	1,771
Annual Cost Cap per Customer	$27	$150	$1,000	-
Annual Cost Cap, Total	**$36,855**	**$60,750**	**$1,000**	**$98,605**
Projected Cost of Compliance[1]	***$12,053***	***$19,867***	***$327***	***$32,247***

Notes: (1) The Town of Windsor is to determine the allocation among the different customer classes.

1.9 REPS RIDER

In accordance with Rule R8-67(b)(1)(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 ESTIMATE OF REPS RIDER COSTS

	2020	2021	2022
Total Projected REPS Compliance Costs	$976,333	$1,187,260	$1,621,884
Costs recovered through the Fuel Rider	$0	$0	$0
Total Incremental Cost	**$976,333**	**$1,187,260**	**$1,621,884**
Annual REPS Rider - Residential	$489,358	$616,047	$842,437
Annual REPS Rider - Commercial	$478,246	$560,570	$765,043
Annual REPS Rider - Industrial	$8,729	$10,643	$14,403
Projected Annual Cost Caps (REPS Rider)	**$5,592,251**	**$5,466,223**	**$5,517,592**

NCUC Docket No. E-100, Sub 165

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ADDENDUM 2

Federal Energy Regulatory Commission Form 1

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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	BRAND TAP	BRAND DP (102)	1.05	STEEL	16.30	1	1
2	COBB TAP	COBB DP (4)	0.13	STEEL	30.00	1	1
3	PALMER SPRINGS	KERR DAM (1019)	6.18	STEEL HFRAME	8.70	1	1
4	SURRY	SKIFFES (582)	7.92	STEEL TOWER	5.50	1	1
5	POSSUM POINT	SMOKETOWN (145)	8.38	STEEL POLE	8.48	2	2
6	POSSUM POINT	SMOKETOWN (18)	8.28	STEEL POLE	8.48	2	2
7	KELFORD TAP	KELFORD (126)	0.02	STEEL HFRAME	9.00	1	1
8	CLUBHOUSE	CAROLINA (130)	13.49	STEEL HFRAME	9.00	1	1
9	GREENWICH	BURTON (166 & 67)	7.22	STEEL POLE	6.28	2	2
10	DOOMS	534/512 (534)	21.45	STEEL TWR	5.36	1	1
11	EVERETTS	WHARTON (82)	18.98	STEEL HFRAME	8.38	1	1
12	BRANDY DP	70/146 (70)	9.29	STEEL POLE	10.20	2	2
13	ORANGE TAP	11/550 (11)	10.98	STEEL VARIES	8.56	2	2
14	PIONEER SUB	PIONEER SUB (2148)	0.08	STEEL VARIES	6.00	1	1
15	LEBANON TAP	LEBANON SUB (209 & 58)	0.06	STEEL VARES	6.00	1	1
16	171/96	HERBERT (171)	0.03	STEEL VARIES	3.00	1	1
17	1026/93	HERBERT (1026)	0.03	STEEL VARIES	3.00	1	1
18	LEXINGTON	ROCKBRIDGE (26)	4.75	STEEL HFRAME	12.80	1	1
19	COLUMBIA TAP	COLUMBIA DP (4)	1.24	STEEL POLE	13.70	1	1
20	CHESTERFIELD	LAKESIDE (217)	20.69	STEEL HFRAME	9.66	1	1
21	PAMPLIN	MADISONVILLE (154)	4.78	STEEL HFRAME	7.30	1	1
22	224/225	224/235	1.86	STEEL TOWER	4.80	1	1
23	53/243, 72/243	BROWN BOVERI (53 & 72)	2.00	STEEL POLE	12.00	2	2
24	549/60	DOOMS (549)	4.90	STEEL TOWER	4.89	1	1
25	SUMMIT TAP	SUMMIT DP (2090)	0.02	STEEL VARIES	4.00	1	1
26							
27							
28							
29							
30							
31							
32							
33							
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38							
39							
40							
41							
42							
43							
44	TOTAL		153.81		221.39	31	31

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 Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Line No.
636	ACSR	HORIZ VARIES	115		914,674	4,304,350	150,340	5,369,364	1
636	ACSR	VERT 12'	115		1,556,384	330,732	56,065	1,943,181	2
768.2	ACSS	HORIZ VARIES	115		5,727,781		105,238	5,833,019	3
1351.5	ACSR	VARIES	500		184,533,069	46,133,267		230,666,336	4
795	ACSR	VARIES	115		12,071,047	2,097,765	97,122	14,265,934	5
795	ACSR	VARIES	115	40,740	2,460,589	6,616,879	137,973	9,256,181	6
768.2	ACSS	HORIZ 9'	115		1,339,423	224,338		1,563,761	7
768.2	ACSS	HORIZ 9'	115		13,531,028	3,834,978	363,057	17,729,063	8
768.2	ACSS	VERT VARIES	115		8,638,945	1,906,571	292,526	10,838,042	9
1351.5	ACSR	DELTA 24.3	500		29,807,769	17,966,975	851,425	48,626,169	10
768.2	ACSS	HORIZ 9'	115		16,318,446	4,027,774	478,310	20,824,530	11
636	ACSR	VERT 20.6'	115		11,795,692	2,506,585	418,816	14,721,093	12
636	ACSR	VERT 20.6'	115		19,761,249	4,199,265	643,168	24,603,682	13
636	ACSR	VARIES	230		191,642	1,006,123		1,197,765	14
636	ACSR	HORIZ VARIES	230			1,221,236	23,653	1,244,889	15
768.2	ACSS	HORIZ VARIES	115		755,543			755,543	16
768.2	ACSS	VERT VARIES	115		494,070	54,897		548,967	17
636	ACSR	HORIZ 9'	115		7,649,216	1,912,304	229,855	9,791,375	18
636	ACSR	DELTA 16.6'	115		3,900,669	975,167	76,634	4,952,470	19
636	ACSR	HORIZ VARIES	230		1,411,336		32,388	1,443,724	20
768.2	ACSS	HORIZ 9'	115		4,648,261	1,162,065	37,822	5,848,148	21
768.2	ACSS	DELTA 19.6'	230		13,883,199	3,470,800	357,096	17,711,095	22
768.2	ACSS	VARIES	115		2,525,780	924,448	97,183	3,547,411	23
1351.5	ACSR	DELTA 32'	500		2,515,234	13,749,946	303,851	16,569,031	24
795	ACSR	HORIZ VARIES	230		339,650	861,254	11,995	1,212,899	25
									26
									27
									28
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									43
				40,740	346,770,696	119,487,719	4,764,517	471,063,672	44

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ADDENDUM 3

Federal Energy Regulatory Commission Form 715

FERC Form 715

Part 1 – Identification and Certification

FERC Form No. 715
Part 1
IDENTIFICATION AND CERTIFICATION

In compliance with the requirements of this FERC Form No. 715 "Annual Transmission Planning Evaluation Report" set forth by 18 CFR § 141.300, PJM Interconnection, L.L.C. (PJM) is providing this information on behalf of its transmission owners subject to the reporting requirements of this FERC Form No. 715. The following is a list of the PJM transmission owners whose information is included in this report.

- AMP Transmission, LLC
- American Electric Power Service Corporation
- Baltimore Gas and Electric Company
- City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
- City of Rochelle (NextEra)
- Commonwealth Edison Company
- Dayton Power and Light Company
- Duke Energy – Ohio and Kentucky
- Duquesne Light Company
- East Kentucky Power Cooperative
- Essential Power Rock Springs, LLC
- FirstEnergy Operating Companies:
  - Allegheny Power
  - American Transmission Systems, Inc.
  - Jersey Central Power and Light Company
  - Metropolitan Edison Company
  - Pennsylvania Electric Company
  - Trans-Allegheny Interstate Line Company
- Hudson Transmission Partners, LLC
- Neptune Regional Transmission System, LLC
- ITC Interconnection, LLC
- Ohio Valley Electric Coop
- PECO Energy Company
- Pennsylvania Power and Light Company
- Pepco Holdings, Inc. (PHI)
  - Atlantic City Electric Company
  - Delmarva Power and Light Company
  - Potomac Electric Power Company
- Public Service Electric and Gas Company
- Rockland Electric Company
- Southern Maryland Electric Cooperative
- UGI Utilities, Inc. - Electric Division
- Virginia Electric & Power Company

This Part 1 contains each member transmission owner's Identification and Certification Form. Requests for this information is to be directed to the regional contact below.

Regional Contact Information

Address: PJM
2750 Monroe Blvd.
Audubon, PA 19403

Contact Person: Mark J. Kuras
Title: Senior Lead Engineer
Reliability Compliance
Phone: (610) 666-8924
e-mail: mark.kuras@pjm.com

AMP TRANSMISSION

FERC FORM 715
ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
Part 1: Identification and Certification
April 1, 2019

Transmitting Utility Name AMP Transmission

Transmitting Utility Mailing Address

AMP Transmission
1111 Schrock Road
Suite 100
Columbus, OH 43229

Contact Person

Name	Ryan Dolan
Title	Director of Transmission Planning
Phone	614-540-6938
Fax	614-540-6399
e-mail Address	rdolan@amppartners.org

Certifying Official

By affixing my signature, I certify that the information supplied in this filing by my Transmitting Utility is accurate.

Signature	Edward D. Tatum
Name	Edward D. Tatum, Jr
Title	Vice President Transmission
Phone	614-540-0941
e-mail Address	etatum@amppartners.org

OHIO VALLEY ELECTRIC CORPORATION - 2019 FILING

FERC FORM 715 - ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

PART 1 -- IDENTIFICATION AND CERTIFICATION

1. Transmitting Utility Name(s):

   Ohio Valley Electric Corporation on behalf of itself and the Indiana-Kentucky Electric Corporation [hereinafter referred to as "OVEC/IKEC"]

2. Transmitting Utility's Designated Agent's / Service Provider's Mailing Address:

   P.O. Box 468
   Piketon, OH 45661

3. Contact Person: S. R. Cunningham
   Electrical Operations Director
   Ohio Valley Electric Corporation

   Phone: (740) 289-7217
   Fax: (740) 289-5000
   E-mail: scunning@ovec.com

4. Certifying Official:

   The undersigned certifies that he has examined the accompanying report; that to the best of his knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the above named transmitting utilities

   Robert A. Osborne
   Vice President & COO
   Ohio Valley Electric Corporation

   Dated: March 29, 2019

FERC FORM 715
ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
Part 1: Identification and Certification
April 1, 2019

Transmitting Utility Name UGI Utilities, Inc. – Electric Division

Transmitting Utility Mailing Address

One UGI Center

Wilkes-Barre, Pa 18711

Contact Person

Name Vincent A. DeGiusto

Title Senior Manager Planning & Operations

Phone 570-830-1289

e-mail Address vdegiustojr@ugi.com

Certifying Official

By affixing my signature I certify that the information supplied in this filing by my Transmitting Utility is accurate.

Signature Eric W Sorber

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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
Part 1: Identification and Certification
April 1, 2018

Transmitting Utility Name Southern Maryland Electric Cooperative, Inc. (SMECO)

Transmitting Utility Mailing Address 14950 Cooperative Place, P.O. Box 1937

Hughesville, MD 20637-1937

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April 1, 2019

Transmitting Utility Name Public Service Electric & Gas

Transmitting Utility Mailing Address
80 Park Plaza, T18
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Newark, NJ 07102

Contact Person

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Transmitting Utility Name PPL Electric Utilities

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Transmitting Utility Name
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Commonwealth Edison
Delmarva Power
PECO
Potomac Electric Power Company

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Transmitting Utility Name	Atlantic City Electric Baltimore Gas and Electric Commonwealth Edison Delmarva Power PECO Potomac Electric Power Company
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Transmitting Utility Name Rockland Electric Company

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April 1, 2019

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Transmitting Utility Mailing Address

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Transmitting Utility Name FirstEnergy Corp.

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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
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April 1, 2019

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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
Part 1: Identification and Certification
April 1, 2019

Transmitting Utility Name East Kentucky Power Cooperative

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Contact Person

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FERC FORM 715
ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
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April 1, 2019

Transmitting Utility Name Duquesne Light Company

Transmitting Utility Mailing Address
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Part 1: Identification and Certification
April 1, 2019

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Transmitting Utility Mailing Address 10900 Nuckols Road

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April 1, 2019

Transmitting Utility Name Duke Energy Ohio and Kentucky

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April 1, 2019

Transmitting Utility Name The Dayton Power and Light Company

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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
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April 1, 2019

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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
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Transmitting Utility Name

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Baltimore Gas and Electric
Commonwealth Edison
Delmarva Power
PECO
Potomac Electric Power Company

Transmitting Utility Mailing Address

Thomas Leeming

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Signature	
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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
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April 1, 2019

Transmitting Utility Name City of Rochelle

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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
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Transmitting Utility Name Atlantic City Electric
Baltimore Gas and Electric
Commonwealth Edison
Delmarva Power
PECO
Potomac Electric Power Company

Transmitting Utility Mailing Address Thomas Leeming

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Contact Person

Name Thomas Leeming

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AMP TRANSMISSION

FERC FORM 715
ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
Part 1: Identification and Certification
April 1, 2019

Transmitting Utility Name AMP Transmission

Transmitting Utility Mailing Address

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Signature	___________________________________
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ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

Part 1: Identification and Certification
April 1, 2019

Transmitting Utility Name(s) (Collectively referred to as "AEP")

Appalachian Power Company
Indiana Michigan Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
Wheeling Power Company

AEP Appalachian Transmission Company
AEP Kentucky Transmission Company
AEP Indiana Michigan Transmission Company
AEP Ohio Transmission Company
AEP West Virginia Transmission Company

Transmitting Utility
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FERC Form 715

Part 2 – Power Flow Base Cases

As Virginia Electric and Power Company's most recently filed FERC Form 715 was filed by PJM, Part 2 to the Form 715 is not specific to the Company, and is therefore not being provided with the Company's 2020 IRP submittal

FERC Form 715

Part 3 – Transmitting Utility Maps and Diagrams

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INFORMATION REDACTED

Hard copies to be submitted on or by September 1, 2020 (*see Order Further Extending Suspension of Requirement for Filing Paper Copies* issued on April 16, 2020, in Docket No. M-100, Sub 158)

FERC Form 715

Part 4 – Transmission Planning Reliability Criteria

ELECTRIC TRANSMISSION PLANNING CRITERIA

Electric Transmission Planning Department
Version 16
Effective 3/15/2019

Approved By Name and Title	Signature	Date Approved
J. R. Bailey Manager Electric Transmission Planning & Strategic Initiatives	J R Bailey	3/11/2019

Table of Contents

A. Scope and objective

The function of the transmission system is to transport power from generating resources to distribution systems in order to serve the demand of the end-user customers. Reliable transmission system operation implies maintaining continuity of service at sufficient voltage levels without overloading equipment under a wide range of operating conditions.

Virginia Electric and Power Company is commonly referred to as Dominion Energy Virginia (DEV). For the purpose of this document, "DEV transmission system" refers to the transmission system owned by Dominion Energy Virginia. "Transmission system" refers to networked and radial facilities within the DEV system at voltage levels of 69, 115, 138, 230, and 500 kV. This document provides approved criteria upon which the needs for reinforcements and enhancements to the DEV transmission system are determined.

DEV's transmission planning criteria ensures adherence to the transmission planning standards of the North American Electric Reliability Corporation (NERC) and those of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations (RRO) of NERC. Unless noted, the Criteria in this document apply to generation, transmission, and end user facilities.

B. National and regional criteria and guides

B.1. NERC planning standards

The North American Electric Reliability Corporation was established to promote the reliability of the bulk electric systems of North America. NERC coordinates reliability standards for the power systems of the United States, the bordering provinces of Canada, and a portion of Mexico. NERC has developed planning standards to ensure the reliable operation of the interconnected bulk electric systems. These standards can be found at the NERC homepage.

The DEV Transmission Planning Criteria provides a description of how DEV performs simulated testing of the interconnected transmission system to determine its ability to withstand probable and extreme contingencies.

B.2. Regional reliability planning standards

NERC consists of eight regional reliability organizations. DEV is a member of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations of NERC. DEV plans the bulk electric system (BES) in coordination with PJM, its Transmission Planner (TP), to meet the requirements of NERC and SERC.

B.3. PJM planning standards

The DEV transmission system is integrated into planning and operations of the PJM Interconnections, L.L.C. RTO (PJM). PJM manages a regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM annually develops a Regional Transmission Expansion Plan (RTEP) to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. The criteria PJM uses in developing the RTEP is set forth in PJM Manual 14B – PJM Region Transmission Planning Process.

C. Transmission planning, steady-state criteria

C.1. Planning principles and standards

The transmission system must perform reliably for a wide range of conditions. Because system operators can exercise only limited direct control, it is essential that studies be made in advance to identify the facilities necessary to assure a reliable transmission system in future years.

The voltages and equipment loadings on the transmission system should be within acceptable limits, both during normal operation and for an appropriate range of potential system faults and equipment outages. The more probable contingency conditions should not result in voltages or equipment loadings beyond emergency limits. These 'emergency limits' can vary based on equipment type and allowable time period.

Tables 1A and 1B specify outage events that are analyzed by DEV at the forecasted load levels to determine if any thermal or voltage violations exist. Thermal capability is given with equipment ratings in amps or MVA. Voltage limits are in reference to the nominal design voltage. Adherence to the criteria given in these tables ensures that DEV's transmission system meets the applicable reliability requirements of NERC, SERC, and PJM.

System readjustment is allowed when attempting to reduce line loadings or improve voltage profile (only as allowed by NERC Criteria). System readjustments considered in planning analysis include:

- Generation re-dispatch (excludes nuclear generation)
- Phase angle regulator adjustment[1]
- Load tap changer adjustment
- Capacitor bank switching
- Line switching
- Inductor switching

Loadings on DEV transmission facilities over their normal rating, following a contingency, must be adjusted back down to normal rating within the time frame of the appropriate term emergency rating. Any of the above listed system readjustments are allowable in this situation as DEV employs 8 hour short-term emergency ratings and 15 minute load dump ratings on transmission equipment, which allows sufficient time to implement any adjustments that reduce loadings to the normal rating.

Loadings on facilities over their short-term emergency ratings, following a contingency, must be adjusted back down to the short-term emergency rating within the time frame of the short term emergency rating using the system readjustments listed above.

[1] *For DEV, phase angle regulator adjustment is used to relieve loadings on the 115kV system in Yorktown and Chesapeake Energy areas. Phase shifting transformers control the division of real power among parallel paths. Chesapeake Energy Center and Yorktown Power Station have phase shifters between the 230 kV and 115 kV systems. The phase shifter transfers load from one voltage level to the other. Phase angle adjustment will be allowed within the parameters noted in PJM's Manual 14B – PJM Region Transmission Planning Process (RTEP Reliability Planning section).*

If the criteria described in this document cannot be met, mitigation plans are developed. A valid mitigation plan will bring the system into compliance through the most judicious use of a variety of feasible options. These include the development of an operator action plan in conjunction with the use of short term ratings, generation re-dispatch, phase angle regulator adjustments, bus-tie switching, Remedial Action Schemes, or the installation of a physical reinforcement.

A Remedial Action Scheme (RAS), as interpreted from the NERC Reliability Standards Glossary of Terms, is designed to detect abnormal system conditions and take automatic corrective action to provide acceptable transmission system performance. The RAS isolates equipment other than faulted elements and/or reconfigures equipment outside of a zone containing faulted elements. An RAS may be applied as required to address thermal, voltage, or stability issues in accordance with NERC Transmission Planning (TPL) Standards and is subject to the RAS requirements of NERC Protection and Control (PRC) Standards 012 through 017. An RAS does not include automatic restoration to service of un-faulted elements within a faulted zone, under frequency and under voltage load shedding schemes, conventional generator out of step tripping schemes, or remote backup tripping schemes. DEV reviews all existing RASs periodically and adjusts settings as deemed necessary. DEV primarily installs RASs as a temporary measure until a more robust solution can be completed to provide acceptable system performance. Operating steps implemented as part of a Remedial Action Scheme shall be considered, provided that the failure of such system does not result in cascading outages or overloads.

In addition to those events and circumstances included in Tables 1A and 1B, Table 1C defines more severe but less probable scenarios that should also be considered for analysis to evaluate resulting consequences. As permitted in the NERC Planning Standards, judgment shall dictate whether and to what extent a mitigation plan would be appropriate.

Table 1A Steady-State Performance PLANNING Events and Dominion Energy CRITERIA

HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	No	No	94% N	95%	105%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	93%	105%
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	No[9]	No[12]	94% STE	93%	105%
		2. Bus Section Fault	SLG	Yes	Yes	Notes "A", "B" & "C"	90%	105%
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	Yes	Yes	Notes "A", "B" & "C"	90%	105%
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	Yes	Yes	Notes "A", "B" & "C"	90%	105%
P3 Multiple Contingency [see Dominion Energy Note "D" & "E"]	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	93%	105%
P4 Multiple Contingency *(Fault plus stuck breaker[10])* [see Dominion Energy Note "E"]	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	Yes	Yes	Notes "A", "B" & "C""	90%	105%
P5 Multiple Contingency *(Fault plus relay failure to operate)* [see Dominion Energy Note "E"]	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	Yes	Yes	Notes "A", "B" & "C"	90%	105%

Table 1A continued on next page

Table 1A Steady-State Performance PLANNING Events and Dominion Energy CRITERIA *(continued)*

HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)* [see Dominion Energy Note "E"]	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	Yes	Yes	Notes "A", "B" & "C"	90%	105%
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Yes	Yes	Notes "A", "B" & "C"	90%	105%

Dominion Energy Notes for Table 1A

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

Note "A" - For thermal overloads greater than 100% of Load Dump (LD) rating, system reinforcements will be required.

Note "B" - For thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating, system reinforcements may NOT be required if system adjustments can reduce thermal overloads to less than 100% of Short Term Rating (STE).

Note "C" - For thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating, system reinforcements may NOT be required if the loss of consequential load up to 300MW achieves a return to less than the STE rating.

Note "D" - See *Section C.2.1.3 – Critical stress case development and studies* for details.

Note "E" - Areas of the system that become radial post-contingency will be included for monitoring of thermal and voltage violations for all load levels served by the radial.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump

Table 1B Steady-State Performance PLANNING Events and Dominion Energy CRITERIA

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	No	No	94% N	102.5%	107%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	101%	108%
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	No[9]	No[12]	94% STE	101%	108%
		2. Bus Section Fault	SLG	No[9]	No	Notes “F”, “G” & “H”	100%	108%
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	No[9]	No	Notes “F”, “G” & “H”	100%	108%
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	Yes	Yes	Notes “F”, “G” and “H”	100%	108%
P3 Multiple Contingency [see Dominion Energy Note “I” & “J”]	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	101%	108%
P4 Multiple Contingency *(Fault plus stuck breaker[10])* [see Dominion Energy Note “J”]	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	No[9]	No	Notes “F”, “G” & “H”	100%	108%
P5 Multiple Contingency *(Fault plus relay failure to operate)* [see Dominion Energy Note “J”]	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	No[9]	No	Notes “F”, “G” & “H”	100%	108%

Table 1B continued on next page

Table 1B Steady-State Performance PLANNING Events and Dominion Energy CRITERIA *(continued)*

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
NERC Category	Initial Condition	Event[1]	Fault Type[2]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed	Thermal Limits	Low Voltage Limit **	High Voltage Limit **
P6 Multiple Contingency *(Two overlapping singles)* [see Dominion Energy Note "J"]	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	Yes	Yes	Notes "F", "G" & "H"	100%	108%
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Yes	Yes	Notes "F", "G" & "H"	100%	108%

Dominion Energy Notes for Table 1B

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

Note "F" – For thermal overloads greater than 100% of Load Dump (LD) rating, system reinforcements will be required.

Note "G" - For thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating system reinforcements may NOT be required if system adjustments can reduce thermal overloads to less than 100% of Short Term Rating (STE).

Note "H" - For thermal overloads less than 100% of Load Dump (LD) rating but greater than 100% of Short Term Emergency (STE) rating, system reinforcements may NOT be required if the loss of consequential load up to 300MW achieves a return to less than the STE rating.

Note "I" - See *Section C.2.1.3 – Critical stress case development and studies* for details.

Note "J" - Areas of the system that become radial post-contingency will be included for monitoring of thermal and voltage violations for all load levels served by the radial.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump

Table 1C Steady-State Performance EXTREME Events and Dominion Energy CRITERIA

NERC TPL-001 Events (excludes DC)					Dominion Energy Criteria		
Category	**Event Note "K"**		**Interruption of Firm Transmission Service Allowed**	**Non-Consequential Load Loss Allowed**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
N-2 Two Contingencies	Loss of a single generator, Transmission Circuit, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service <u>prior to System adjustments.</u>		YES	YES	100% LD	90%	Note "Q"
LAE Local Area Events	Local area events affecting the Transmission System such as:	a. Loss of a tower line with three or more circuits.[11]	YES	YES	100% LD Note "L"	90%	Note "Q"
		b. Loss of all Transmission lines on a common Right-of-Way[11].	YES	YES	100% LD Note "M"	90%	Note "Q"
		c. Loss of a switching station or substation (loss of one voltage level plus transformers).	YES	YES	100% LD Note "N"	90%	Note "Q"
		d. Loss of all generating units at a generating station.	YES	YES	100% LD Note "O"	90%	Note "Q"
		e. Loss of a large Load or major Load center.	YES	YES	100% LD Note "P"	90%	Note "Q"
WAE Wide Area Events	Wide area events affecting the Transmission System based on System topology such as:	a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.	YES	YES	100% LD for both HV and EHV		Note "Q"
		b. Other events based upon operating experience that may result in wide area disturbances.	YES	YES			Note "Q"

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).
N – Normal Rating, STE – Short Term Emergency, LD – Load Dump

<u>Dominion Energy Notes for Table 1C</u>

See separate listing *Table 1 (A, B & C) Footnotes* for superscript numbered footnotes.

Note "K" – For all extreme events evaluated:

- Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Note "L" – The loss of three or more transmission circuits on a common structure should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common structure and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

Note “M” – The loss of transmission circuits on a common right of way should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common right of way and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

Note “N” – The loss of a switching station or substation (one voltage level plus transformers) should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE). The consequential load due to the loss in the affected station is not to exceed 300 MW.

Note “O” – The loss of all generation at a generating station should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE).

Note “P” – The loss of a large load or major load center should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE).

Note “Q” - High Voltage (HV): 105%; Extra High Voltage (EHV): 108%

Table 1 (A, B & C) Footnotes [NERC Standard TPL-001-4]

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage apply to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C.1.1. Voltage limits at generating stations

Plant auxiliary power equipment requires adequate voltages in order to maintain reliable operation of online generators as well as to provide for reliable startup capability for offline generators. Minimum transmission voltage limits specific to generating stations, are used to ensure plant auxiliary equipment is provided with adequate voltages during both online and offline operation. These limits apply to all classes of generation except wind turbines, for which the system transmission voltage limits are adequate.

In cases where plant auxiliary power is supplied by power transformers not equipped with a load tap changer (LTC) or equivalent voltage control device, the voltage limits at the low side of the Generator Step-up Unit (GSU) are established as 0.95 per unit (minimum) and 1.05 per unit (maximum) unless otherwise specified by the generator owner.

C.2. Detailed steady-state criteria

C.2.1. System load level

C.2.1.1. Peak period studies

The peak load period must be studied to determine future requirements for the transmission system. The basic references for system peak load to be used in studies for future years are the total corporate system load projection provided by the PJM Load Analysis. The actual peak load in any given future year is likely to be higher or lower than the forecast value. A ‘50/50’ forecast provides a peak load projection with a 50% probability that the actual peak will be higher than the level forecasted in that year.

C.2.1.2. Off-peak period studies

Studies should also be conducted for the purpose of determining risks and consequences at light load or shoulder peak conditions, and for any other period for which system adequacy cannot be evaluated from peak period study results. For these off peak periods, it is assumed that the number of hours of occurrence is substantially higher than the number of hours at or near peak load levels. In addition, severe drought conditions effecting hydro generation plant availability and its impact on the transmission system are also studied.

C.2.1.3. Critical stress case development and studies

DEV studies the transmission system under both normal and critical system stress conditions. For NERC Category P3 Analysis, DEV will outage the most critical generator in the area being studied, and the resulting power flow case is considered a critical stress case. Under this critical stress case condition, the generator being studied is taken off-line and the remaining generators connected to the DEV System are proportionally increased to make-up for the lost generation. If there are not enough generation resources available within the DEV system, or the use of DEV generation resources would not provide an adequate base case, then PJM generation resources should be utilized to make-up any generation deficiency. This resulting critical stress case is then analyzed for NERC Compliance based on the transmission contingency events listed in Table 1A and Table 1B Category P3(Multiple Contingency).

C.2.2. Power transfers

All studies should consider known firm power transfers affecting the DEV transmission system. This includes known firm transmission service reservations, including those with rollover rights, as well as parallel path power transfers through the system that may impact system reliability.

DEV is part of a larger regional power system that must be capable of withstanding certain levels of power transfers between or through sub areas of the region. PJM conducts load and generator deliverability tests for specific sub areas as part of the Regional Transmission Expansion Plan (RTEP) process to determine whether the system can accommodate these transfers. The DEV transmission system must meet this transfer Load and Generator Deliverability Requirement. A description of the deliverability testing procedures can be found in PJM Manual 14B – PJM Region Transmission Planning Process. SERC Reliability Corporation also performs transfer limit testing to trend the strength of the transmission system. The results of these studies may also indicate a need to increase transfer strength on the DEV system.

DEV routinely tests the capability of the transmission system to transfer reasonable amounts of power (approximately 2000 MW) in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities. Such tests are conducted under two basic scenarios: (1) with all transmission facilities in service at or below the maximum continuous normal rating; and (2) with one transmission circuit or transformer out of service while maintaining the loading on all remaining transmission facilities at or below the maximum continuous emergency rating. Any new facilities connected to the transmission system shall not significantly decrement, the First Contingency Incremental Transfer Capability (FCITC) for transfers between utilities. A FCITC decrement in excess of 5% will be considered significant in most cases.

C.2.3. Equipment ratings

Allowable loadings for transmission facilities are maintained by DEV in an equipment ratings database. In most cases, equipment is given at least a normal rating and one emergency rating. Some equipment is given multiple emergency ratings. These ratings differ by allowable duration, and are referred to as short-term, long-term, and load dump.

The specific procedure used for determining equipment ratings is outlined in the DEV Transmission Facility Ratings Methodology technical reference document.

C.2.4. Circuit breaker interrupting capability

All Facilities must equal or exceed the fault duty capability necessary to meet system short circuit requirements as determined through short circuit analyses, and shall fully comply with the latest ANSI/IEEE C37 standards for circuit breakers, switch gear, substations, and fuses.

Under normal conditions, the current through a circuit breaker shall not exceed the maximum continuous ratings of that breaker. Further, a circuit breaker shall have sufficient capability to interrupt a close-in single phase fault or three phase-to-ground fault.

C.2.5. Reactive power planning

The objective of system reactive power planning is to efficiently coordinate the reactive requirements of the transmission and distribution systems to satisfy voltage criteria. Meeting this objective ensures voltage stability, provides generator auxiliary power systems on the distribution system with adequate voltage, and minimizes transmission losses and reactive interchange. System reactive requirements can be controlled by changing generation excitation, operating synchronous condensers, changing transformer tap positions, switching transmission and distribution level static capacitors, switching shunt reactors, and adjusting solid-state reactive compensation devices (SVCs, etc.).

The DEV system is planned so that transmission voltages will be maintained within an acceptable range for normal and emergency conditions as described in Tables 1A and 1B.

Low transmission voltage will lead to undesirable effects in both the transmission and distribution systems, such as higher losses, reduced insulation life, and reduced effectiveness of capacitors. These effects would also increase the difficulty in recovering from low transmission voltage situations. The outage events analyzed to assess voltage adequacy are the same as those listed in Tables 1A and 1B. Distribution facilities which are maintaining power factors at the Transmission Point of Interconnection (POI) that are less than PJM's requirement (per Manual 14B – PJM Region Transmission Planning Process) and DEV's requirement (97.3% lagging) may not be able to maintain satisfactory voltage to customers served from these distribution facilities when transmission system voltages are at or near the lower voltage limits of normal and emergency transmission system operations.

Conversely, high transmission voltages that exceed operating voltage schedules can stress generation, distribution, and transmission equipment and lead to premature fatigue or even failure.

C.2.6. Radial transmission lines

A Radial transmission line is defined as a single line that has one transmission source, serves load, and does NOT tie to any other transmission source (line or substation).

Unlike load served from a network transmission line having two sources where a downed conductor or structure can be sectionalized for load to be served before repairs are completed, load served from a single source radial transmission line cannot be reenergized until all repairs to the line are completed. Accordingly, loading on single source radial transmission lines will be limited to the following:

- 100 MW Maximum
- 700 MW-Mile Exposure (MW-Mile = Peak MW X Radial Line Length)

Once a radial loading limit exceeds any of these thresholds, an additional transmission source is required. Acceptable transmission source includes but is not limited to the following:

- Network from a separate transmission substation source (Preferred)
- Loop back to same transmission substation source
- Normally open network or loop transmission source

C.2.7. Network transmission lines – Limitations on direct-connect loads

A network transmission line is defined as one that connects two network transmission sources (connect to other lines & substations) and a "Tap point" is defined as a direct connection of a customer to a network transmission line without addition of any transmission breaker or breakers to split the line. Network transmission lines facilitate network flows and could serve directly connected (Tapped) loads. In the Dominion Energy system, 500, 230, 138, 115 and 69kV lines are considered transmission, and all with the exception of 500kV could be tapped to serve customer load.

In general, the number of direct-connect loads (tapped facilities) should be limited to four (4); however, Good Utility Practice and sound engineering judgment must be exercised in application of this criteria.

C.2.8. Substation – Limitation on direct-connect loads

The amount of direct-connect load at any substation will be limited to 300MW.

C.2.9. End of life criteria

Electric transmission infrastructure reaches its end of life as a result of many factors. Some factors such as extreme weather and environmental conditions can *shorten* infrastructure life, while others such as maintenance activities can *lengthen* its life. Once end of life is recognized, in order to ensure continued reliability of the transmission grid, a decision must be made regarding the best way to address this end-of-life asset.

For this criterion, "end of life" is defined as the point at which infrastructure is at risk of failure, and continued maintenance and/or refurbishment of the infrastructure is no longer a valid option to extend the life of the facilities consistent with Good Utility Practice and Dominion Energy Transmission Planning Criteria. The infrastructure to be evaluated under this end-of-life criteria are all transmission lines at 69 kV and above.

The decision point of this criterion is based on satisfying two metrics:

1) *Facility is nearing, or has already passed, its end of life, and*
2) *Continued operation risks negatively impacting reliability of the transmission system.*

For facilities that satisfy both of these metrics, this criterion mandates either replacing these facilities with in-kind infrastructure that meets current Dominion Energy standards or employing an alternative solution to ensure the Dominion Energy transmission system satisfies all applicable reliability criteria.

Dominion Energy will determine whether the two metrics are satisfied based on the following assessment:

1. End of Life

Factors that support a determination that a facility has reached its end of life include, but are not limited to,

- **Condition** of the facility, taking into consideration:
    - Industry recommendations on service life for the particular type of facility
    - The facility's performance history
        - Documented evidence indicating that the facility has reached the end of its useful service life
    - The facility's maintenance and expense history
- **Third-party assessment -** While not required, Dominion Energy has the option of seeking a third-party assessment of a facility to determine if industry specialists agree the facility has reached the end of its useful service life

2. Reliability and System Impact

The reliability impact of continued operation of a facility will be determined based on a planning power flow assessment and operational performance considerations. The end-of-life determination for a facility to be tested for reliability impact will be assessed by evaluating the impact on short and long term reliability with and without the facility in service in the power flow model. The existing system with the facility removed will become the base case system for which all reliability tests will be performed.

The primary four (4) reliability tests to be considered are:

1. NERC Reliability Standards
2. PJM Planning Criteria – As documented in PJM Manual 14B – PJM Region Transmission Planning Process
3. Dominion Energy Transmission Planning Criteria contained in this

document

4. Operational Performance – This test will be based on input from PJM and/or Dominion Energy System Operations as to the impact on reliably operating the system without the facility

Additional factors to be evaluated under system impact may include but not be limited to:

1. Market efficiency
2. Stage 1A ARR sufficiency
3. Public policy
4. SERC reliability criteria

Failure of any of these reliability tests, along with the end-of-life assessment discussed herein, will indicate a violation of the End-of-Life Criteria and necessitate replacement as mandated earlier in this document.

After the end of service life and reliability impact of a facility are evaluated and it has been determined that the facility violates the End-of-Life Criteria, a determination will be made as to whether replacement of the facility is the most effective solution for an identified reliability need, or whether an alternative solution should be employed. One or more of the following factors may be considered in determining whether to proceed with facility replacement or with an alternative solution:

- Planning analysis which may include power flow studies
- Operational performance
- System Reliability
- Effectiveness of the alternative as compared to the replacement facility
- Future load growth in the study area
- Future transmission projects or interconnects that impact the study area
- Constructability comparison
- Cost comparison

C.3. Selection of generation dispatch used in DEV Power Flow Studies

The PJM RTEP Power Flow case for the year under study is the starting point for DEV Power Flow Studies. The generation dispatch in the PJM RTEP case is developed based on PJM's Study Methodologies as outlined in PJM's Manual 14B. DEV may modify this generation dispatch to develop a Base Power Flow case which is used as the starting point of DEV's Analysis to support PJM's RTEP Study Process. These modifications may include the following:

- Generating Units which have significant environmental limitations which severely limit the units availability in real time operation may be modeled as being off-line.

- Generating Units which have been identified in DEV's IRP Filings in Virginia/North Carolina as being "Potential" Generation Retirements may be modeled as being off-line.
- Known outages of a generating unit which are consistent with NERC TPL-001 selection criteria may be modeled as being off-line.

The base power flow dispatch provided to DEV in a power flow case which is used to analyze the reliability impact (Feasibility Study/System Impact Study) of generators in the PJM Generation Queue is typically modified by DEV. Since the case provided to DEV typically has all queue generation located on the DEV System as being off-line, DEV will modify the generation dispatch for power flow studies. Specifically, will turn on all higher order queue generators then the queue request under study as the base case condition for the generator under study. To account for this additional generation, generators located on the PJM System are proportional re-dispatched to account for this additional generation.

D. Transmission planning, system stability criteria

D.1. Introduction

There are many different variables that affect the results of a stability study. These factors include:

- pre-fault and post-fault system configuration
- system load level and load characteristics
- generation dispatch patterns and unit dynamic characteristics
- type and locations of system disturbances
- total fault clearing time(s)
- the amount of flow interrupted as a result of switching out a faulted element
- level of detail and accuracy of available models/data
- proximity to other generating units

Many of these factors change in the operating arena on a continuous basis. Every effort should be made to evaluate the most severe, yet credible/probable combinations of line/faults/equipment failures in planning arena. If the system operating condition is known a couple of days in advance of any scheduled maintenance outage, a more accurate assessment/ analysis can be performed which could be more restrictive or less restrictive than the ones studied in planning arena.

D.2. General criteria

The criteria for performing stability simulations near generating stations on the Dominion Energy Virginia (DEV) system supports PJM in its role as Transmission Planner (TP).

For breaker failure backup clearing, it will be assumed that only one pole fails to operate where three separate mechanisms (independent poles) are available as in the case of all 500 kV breakers on DEV system. Stability analysis is not required for units that are not part of the Bulk Electric System (BES) as defined by NERC. In general, generators rated 20 MVA or less in size and with aggregate plant capacity less than or equal to 75 MVA are not part of the BES. The results of stability studies are generally valid for about 15 to 20 seconds following a disturbance. Therefore, disturbance simulations will be carried out to 15 to 20 seconds. The transformer taps are fixed at the pre-disturbance level throughout the simulations since the tap movements take more than 30 seconds.

D.3. Study horizon

Generally, stability studies are performed for the near-term horizon (1-5 years) since the required corrections, if and when warranted, are generally of the following types and can be implemented in a relatively short period of time:

- Shorten the fault clearing time(s) by resetting breaker failure timer(s),replacing relays, or replacing circuit breakers
- Add dual primary protection schemes to mitigate delayed clearing
- Add or tune a power system stabilizer (PSS)
- Apply Remedial Action Scheme (RAS)
- Add out-of-step (OOS) protection
- Install series capacitors
- Establish operating restrictions for a contingency period of short duration covering forced or maintenance outages.

There are several other reasons stability studies concentrate in the near-term horizon. The system representation (load, generation, etc.) in study base cases for a long-term horizon (6-10 years) is inherently uncertain from a dynamics perspective. Some of the future generation in these cases may not materialize and hence may yield erroneous results indicating either unnecessary improvements or a false sense of security. A large number of merchant plants have been delayed or cancelled altogether in the past. The delays or cancellations of such merchant plants require re-studies. The further one goes out in study time horizon, the possible combinations of such uncertainties multiply. Since stability studies are very time consuming, extensive long-term studies become impractical. SERC has recognized this and has acknowledged in its supplement that stability studies for a longer-term planning horizon are not required for full compliance except for new generation that falls into the long-term study horizon.

For identified stability problems that cannot be remedied with the aforementioned solutions, i.e. the probability of the operating condition and/or contingency occurring is deemed high, new transmission infrastructure may be required to ensure stability for safe and reliable operation of the electric grid. In cases where a near-term horizon stability study indicates a potential correction that may require much longer lead time, such as requiring a new transmission line, or if a Generation Interconnection request is for a long-term horizon, the long-term stability study would then be performed.

D.4. Study cycle

It is not practical to perform dynamic simulations for all generating plants every year for all categories listed in Table 1 of the TPL Standards. Therefore, PJM will perform simulations to cover all generating plants over a three-year study cycle unless changing system conditions warrant a shorter interval. In case of a new generation addition or a capacity addition to an existing plant, it should be properly studied prior to its in-service date. Stability analysis in such cases will first be performed by PJM as the Generation Interconnection queue administrator. DEV will review the results of PJM stability analysis and perform any subsequent analysis, if and when deemed necessary.

D.5. Dynamics data collection

PJM will collect dynamic data and submit to SERC as outlined in the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) Procedural Manual.

Dominion Energy Electric Transmission Planning is responsible for submitting dynamic data to PJM for Transmission Owner equipment with dynamic characteristics such as SVCs and STATCOMs.

D.6. Selection of a reference power flow case

Planning arena studies for stability analysis are performed using an estimated snap-shot of the expected system operating conditions for the study period selected. The power flow base cases that match dynamics data for the Eastern Interconnection are prepared by the Multi-regional Modeling Working Group (MMWG) for selected years on an annual basis. The dynamically reduced SERC cases are prepared using three of the MMWG cases, generally every other year. The internal DEV power flow base cases are updated on a regular basis to incorporate the most updated information on facility ratings/upgrades, load, etc.

It is a general practice to incorporate the DEV system representation from the most updated internal base case for the study year into one of the SERC reduced base cases depending on the study year. A validation review is then performed on the combined case to make sure that the stability case thus prepared initializes error free and a 30-second “Drift Run” is performed to insure that the steady-state stability is maintained. This is steady-state condition, NERC TPL-001, Category P0.

D.7. Selection of generation dispatch

The economic dispatch used in internal power flow base cases may not represent conditions which could pose a stability risk. Therefore, the power flow cases may be stressed to test the area or generation under study. For example, increased transfers near generating facilities can have an adverse impact on transient stability and therefore need to be accounted for when creating stressed yet credible system dispatches for the stability studies.

Unit dispatch for transient stability studies also differs from the conventional power flow analysis. Units in the study region are generally dispatched to maximum real power output (Pmax), and at leading power factor at the low side of the GSU provided that the equipment voltage limits are not violated. Specifically, units under study and electrically close that fall within the study region[2] should be dispatched to absorb approximately 50% of the minimum reactive capability (Qmin) without violating the terminal voltage limits (generally 0.95 pu).

D.8. Selection of contingencies

In general, contingency simulations are based on Table 1 of NERC Reliability Standard TPL-001-4. However, all contingencies may not be applicable in a given study due to either breaker arrangement or type of protection scheme employed. Also, if the stability is maintained for a more severe fault condition (e.g. three-phase or two-phase-to-ground), it is not necessary to simulate a fault of less severity (e.g. single-phase-to-ground). If identical equipment is removed from service due to a fault at various locations in a substation, leaving identical post-fault/post-switching system condition, it is not necessary to apply the fault at more than one of such locations. Much depends on the type of station equipment, station arrangement and type of protection schemes applied at a given location.

As for simulating transmission line faults, if there are only two lines from a plant, both should be tested using different power flow cases with different dispatch patterns (see Selection of Generation Dispatch above), faulting the line with highest flow in each case. For a multiple line station, the line carrying the highest power should be the first one to be selected and the remaining lines(s) should be selected based on system experience and sound engineering judgment. In case of any doubt, faults on all lines may need to be simulated. If stability is maintained for a more severe fault scenario (e.g. 3-phase fault), a less severe fault scenario (e.g. SLG) need not be simulated everything else remaining same.

If a line length is short, it may be necessary to check contingencies at the next station. For breaker-failure scenarios, contingencies are selected that would simulate the weakest system condition based on station breaker arrangement and system knowledge. If the failed breaker would trip a generating unit(s) due to breaker arrangement, that contingency may be omitted depending on the results of more severe contingencies.

The voltage stability analysis shall first be performed by power flow studies. Once potential voltage instability problem is identified in a power flow study (or observed in the field), a time-domain analysis shall then be performed for confirmation and mitigation of the problem.

D.9. What to look for in study results

Checks are performed to make sure all on-line units initialize properly without any error messages. A 30-second "drift run" should be performed prior to any stability analysis to ensure successful initialization. This corresponds to the steady-state condition defined as Category "P0" in Table 1 of NERC TPL-001.

Checks are performed to make sure the system is stable with acceptable voltages for selected contingencies, and the damping ratio is 3% or better for inter-area oscillations and 4% or better for local mode oscillations. Solutions identified in section D3 are considered for situations where transient voltage or oscillation damping is not met, or if transient stability is not maintained. If the inter-area oscillations have an unacceptable damping ratio and other entities' units are found to be participating significantly, then it may require a joint study between the affected parties. Power system stabilizers are recommended, especially if

[2] Engineering judgment must be applied in selecting the generators that *electrically close* to unit(s) under study.

oscillation damping criteria is marginally satisfied. N-1-1 contingencies with no redispatch are considered to ensure transient stability is maintained with positive damping. This provides a safety margin for any planned conditions and/or unexpected contingencies that could occur. If the oscillation damping is positive but does not meet the criteria above, operation restriction may be applied to ensure sufficient oscillation damping for both local and inter-area modes of oscillations. Generator out-of-step (OOS) protection is highly recommended on all BES generating units to ensure the protection and safety of the generator itself.

For system conditions and selected contingencies that results in generator transient instability, additional analysis is performed to quantify the risk of cascading events and potential for blackout conditions. Cascading failure analysis will consider a risk-based study of the loss of the generating unit based on expected protection and control as well as unexpected tripping. Depending on the size and expanse of the affected area, other solution options, operating restrictions, or transmission investments may be considered.

Since the transmission planning studies are performed for an estimated operating condition for a future date, the post disturbance thermal loading and voltage levels may vary widely when real disturbance occurs. This is because the load, generation dispatch and available reactive resources in real time may be quite different than the ones studied in planning arena. For this reason, the thermal limits and voltage conditions should be checked using the real-time contingency analysis tool.

D.10. Implementation procedure

Stability analysis may warrant corrections or additional requirements in order to meet the stability criteria listed in this document. The implementation procedure for such items depends on the type of corrections warranted and the nature of installation. The following is a general guideline for Transmission Planning to get such fixes implemented.

D.10.1. For existing installations

- Corrections related to transmission fault clearing times near generating stations that can be resolved by changes to existing relay set points shall be communicated to Electric Transmissions Circuit Calculations group for implementation. PJM should also be informed as to the results of this analysis.
- A Capital project shall be generated for corrections related to transmission fault clearing times near generation stations that require baseline improvements such as new or additional equipment. All Capital projects shall first be validated, approved and assigned cost and construction responsibility by the PJM Regional Transmission Expansion Planning (RTEP) process.
- Output restrictions and/or unit trip(s) for the next pending contingency condition identified by DEV in routine planning studies, will be communicated to the SOC. In turn, the SOC shall inform PJM for implementation as appropriate.
- In case of scheduled maintenance or construction outages, the results/recommendations shall be conveyed to the person through whom

the stability analysis request came to the stability engineers. For example, if a Project Manager requests such analysis to the load Planning Engineer, the stability engineer shall forward his analysis to the load Planning Engineer. If SOC requests such analysis, the results/recommendations shall be forwarded to SOC which in turn shall inform PJM for implementation as appropriate.

D.10.2. For new installations or capacity additions

New generating resources are studied as part of the PJM Generation Interconnection Queue process. PJM shall document the fault clearing time requirements and/or any additional protection requirements in its Impact Study report. PJM shall also communicate the requirements on the generation side to the GO requesting the Interconnection in PJM Queue. For the transmission related requirements, Dominion Energy shall communicate these to the Substation Engineering group for design and implementation.

E. Nuclear plant interface coordination

E.1. Introduction

Nuclear power plants have special needs for backup station service not found in other plants. In order to safely shut down a nuclear unit, the station service must have an adequate supply of power under tight voltage tolerances to the safety systems. Although nuclear plants have diesel generators as a backup supply, their preferred power source is the transmission grid. This allows multiple levels of redundancy which is the hallmark of the nuclear plant's endeavor to the highest level of safety.

E.2. NRC regulations

The Federal Nuclear Regulatory Commission (NRC) lays out certain regulations on the design and operation of Nuclear Plants. **Appendix A of Regulation 10 CFR 50** "General Design Criteria for Nuclear Power Plants" states:

> *"Criterion 17--Electric power systems.* ***.*** *An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.*
>
> *The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.*
>
> *Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate*

rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

The above regulation General Design Criterion 17 is often abbreviated "GDC-17."

E.3. Design requirements

PJM and Dominion Energy Electric Transmission Planning will design the system to meet the GDC-17 requirements. In order to provide adequate voltage to safety systems, the Nuclear group periodically provides Nuclear Plant Interface Requirements (NPIR) to Dominion Energy Electric Transmission. Dominion Energy transmission planners should consult the latest version of applicable Interface Agreements between Dominion Energy Electric Transmission and the nuclear plants for applicable normal and emergency voltage limits, voltage drops and contingency scenarios.

Because emergency systems require adequate voltage immediately following an event, transmission LTC's should be locked post-contingency.

For violations of the NPIRs, the transmission planner will contact the GDC-17 coordinator for Electric Transmission Planning. PJM/Dominion Energy Electric Transmission Planning will notify Dominion Energy Nuclear of any NPIR criteria violations. Transmission study criteria violations based on standard PJM/Dominion Energy criteria testing will be handled by the procedures described in the PJM agreements and manuals. For study violations that are beyond applicable PJM criteria, Dominion Energy Nuclear will determine if any further action is required and respond to Dominion Energy Electric Transmission Planning. Dominion Energy Electric Transmission Planning will work with PJM to resolve concerns identified by Dominion Nuclear.

For contingencies more severe than those within the NPIRs, standard planning voltage range criteria will be applied.

E.4. Underfrequency studies

The underfrequency load shed program (UFLS) should be designed to coordinate with station underfrequency trip settings. The North Anna reactor coolant pump (RCP) is set to trip at 56.55 Hz with a time delay of 100 milliseconds. The Surry reactor coolant pump (RCP) is set to trip at 58.05 Hz with a time delay of 100 milliseconds.

E.5. Angular stability studies

Angular stability studies are performed on nuclear plants using the standard methodology used for any synchronous machine. The results of these studies should be forwarded to Nuclear Engineering.

E.6. System analysis protocol

The Nuclear Switchyard Interface Agreement System Analysis Protocol (CO-AGREE-000-IA1-4 or its successor) outlines the types and frequency of studies which may be performed in support of the nuclear plant. It also specifies the type of communications necessary and the frequency of the analysis. In order to show compliance with NERC Standard NUC-001-2 (or its successor), the GDC-17 coordinator shall retain evidence of communications with the appropriate nuclear contacts.

E.7. Changes to the system

The NERC standard NUC-001-2, R8 states that the "…Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs."

F. References

- NERC Planning Standard TPL-001 .
- Transmission System Performance SERC Supplement
- NERC Reliability Standard NUC-001
- Nuclear Switchyard Interface Agreement CO-AGREE-000-IA1
- Nuclear Switchyard Interface Agreement System Analysis Protocol CO-AGREE-000-IA1-4
- PJM Manual 39 – Nuclear Plant Interface Coordination
- Manual 14B – PJM Region Transmission Planning Process

G. Abbreviations & definitions

- **AAR** - Auction Revenue Rights (see PJM Manual 06 – Financial Transmission Rights for more details)
- **ANSI** - American National Standards Institute
- **ERAG** - Eastern Interconnection Reliability Assessment Group
- **FCITC** - First Contingency Incremental Transfer Capability
- **Good Utility Practice** - Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition.
- **GSU** - Generator Step-up Transformer
- **IEEE** - Institute of Electrical and Electronic Engineers
- **MMWG** - Multi-Regional Modeling Working Group
- **NERC** - North American Electric Reliability Corporation
- **POI** - Point of Interconnection
- **RTO** - Regional Transmission Organization
- **PSS** - Power System Stabilizer
- **SERC** - SERC Reliability Corporation

H. Revision History

Revision Date	Revision #	Description	Revised By	Effective Date
08/24/1999	0.0*	Original document created to meet the requirements of NERC Planning Standard I.C.S1.M1.	ET Planning staff	08/24/1999
05/01/2001	1.0*	See Details for Revision 1.0 below	ET Planning staff	05/01/2001
09/07/2005	2.0*	See Details for Revision 2.0 below	ET Planning staff	09/07/2005
05/29/2007	3.0*	See Details for Revision 3.0 below	ET Planning staff	05/29/2007
12/22/2009	4.0*	See Details for Revision 4.0 below	ET Planning staff	12/22/2009
12/22/2011	5.0*	See Details for Revision 5.0 below	William F. Bigdely	12/22/2011
10/10/2012	6.0	See Details for Revision 6.0 below	William F. Bigdely	10/10/2012
11/22/2013	7.0	See Details for Revision 7.0 below	William F. Bigdely	11/22/2013
03/31/2014	8.0	See Details for Revision 8.0 below	William F. Bigdely	03/31/2014
07/16/2014	9.0	See Details for Revision 9.0 below	William F. Bigdely	07/16/2014
01/09/2015	10.0	See Details for Revision 10.0 below	William F. Bigdely	01/15/2015
03/26/2015	11.0	See Details for Revision 11.0 below	William F. Bigdely	03/27/2015
12/15/2015	12.0	See Details for Revision 12.0 below	William F. Bigdely	01/01/2016
05/15/2017	13.0	See Details for Revision 13.0 below	William F. Bigdely	06/01/2017
03/29/2018	14.0	See Details for Revision 14.0 below	William F. Bigdely	04/01/2018
12/13/2018	15.0	See Details for Revision 15.0 below	William F. Bigdely	01/01/2019
03/11/2019	16.0	See Details for Revision 16.0 below	William F. Bigdely	03/15/2019

*For these revisions, the planning guideline was an attachment within the DEV facilities connection requirements document. Associated comments for these revisions do not necessarily apply to the contents of the planning guideline specifically.

Details for Revision 1.0

- Revised to include information regarding Dominion's generation interconnection procedures/process

Details for Revision 2.0

- Revised to reflect transition from old NERC Planning Standards to NERC Reliability Standards, including changing the naming convention of all referenced standards throughout the document.

Details for Revision 3.0

- Revised to reflect the following:
    - Updates to NERC Reliability Standards
    - Dominion's PJM Membership
    - References to new SERC regional studies processes

Details for Revision 4.0

- Revised to reflect the following :
    - PJM Generation Queue Changes Section 4
    - General Revisions all sections

Details for Revision 5.0

- Revised the following:
  - Section 2.12: Clarified content regarding synchronizing of facilities.
  - Exhibit A: Changed loading criteria to not exceed emergency rating of transmission facility.
  - Various errata changes.

Details for Revision 6.0

- Overhaul and expansion of entire Planning Criteria.
- Document previously called “Transmission Planning Guidelines”

Details for Revision 7.0

- Updated to include future reference to TPL-001-4 (R1 and R7 NERC enforcement date of 01-01-2015)
- Updated titles for approval process
- Various errata changes

Details for Revision 8.0

- Expanded description for Section G.1. TAPPING LINE BELOW 100 MW LOAD to emphasize the requirement of a fused bypass arrangement.
- Recreated diagrams throughout for consistency of style.

Details for Revision 9.0

- Added section C.2.8 - End of life criteria
- Reformatted headers to improve PDF navigation via bookmarks.

Details for Revision 10.0

- Clarifications and annual review.
- Reformatted approval area and moved to title page.
- Reformatted Revision History and moved to end of document (Section J).
- Modified throughout to reflect NERC Reliability Standard TPL-001-4, including replacement of Tables 1A and 1B and deletion of “Category D Multiple Testing Requirements” (previously Section C.2.7 in Revision 9.0 document).
- Section C.2.6 Radial lines: Expanded to introduce new criteria and metrics.
- Section C.2.7 Network transmission lines – Limitations on direct-connect loads: Inserted new section.
- Section D.4 Study cycle – Clarified that PJM (not DEV) performs simulations to cover all generating plants over a three-year study cycle (not five-year).
- Section G: Modified electrical arrangements and clarified lines of demarcation.

Details for Revision 11.0

- Section C1, Table 1A Notes – Added Note “C”
- Section C1, Table 1B Notes – Added Note “G”; re-numbered other notes to differentiate from Table 1A [Note G became Note I in v15]
- Section D7 Selection of generation dispatch – Rephrased the content to improve clarity.

Details for Revision 12.0

- Changed references of Special Protection System (SPS) to Remedial Action Scheme (RAS).
- Tables 1A and 1B: Removed references to DC line (does not apply to Dominion), and
- Table 1A, Note B and Table 1B, Note F: Clarified "may NOT be required if the loss of consequential and non-consequential load up to 300MW achieves a return to the STE rating."
- Section E.3. Updated NPIR Limits.
- Former Section F (Transmission Line Connections – Generation) and former Section G (Load Criteria – End User) have been removed from this document and integrated into the Facility Interconnection Requirements as Sections 5 and 6.
- Section G Abbreviations & definitions: Added definition of "Good Utility Practice".

Details for Revision 13.0

- Revised references for new Dominion Energy corporate identity.
- Section C.1. Added Table 1C Steady-State Performance EXTREME Events and Dominion Energy CRITERIA, and associated notes; refined notes for Tables 1A and 1B.
- Added Section C.2.8. Substation – Limitation on direct-connect loads.

Details for Revision 14.0

- Clarified that some notes to Tables A, B and C are "Dominion Energy" notes.
- Edited Dominion Energy Note "B" for Table 1A and Note "F" for Table 1B to remove phrase "and non-consequential" [load]. [Note F became Note H in v15]
- Edited Dominion Energy Note "C" for Table 1A and Note "G" for Table 1B to refer to new section C.2.1.3. [Note G became Note I in v15]
- Added Section C.2.1.3 - Critical stress case development and studies

Details for Revision 15.0

- Reviewed to ensure alignment with Facility Interconnection Requirements, v15, effective 1/1/2019.
- Tables 1A, 1B, 1C: Added new notes to Tables 1A and 1B, requiring re-labeling of notes in Tables 1A, 1B and 1C as follows:

Previously	Now
A	**A**
B	**B (edited)**
-	**C (NEW)**
C	**D**
-	**E (NEW)**
D	**F**

Previously	Now
E	**G**
F	**H**
G	**I**
-	**J (NEW)**
H	**K**
I	**L**

Previously	Now
J	**M**
K	**N**
L	**O**
M	**P**
N	**Q**

- Section C.1. Planning principles and standards - Simplified reference to Nuclear generation re-dispatch.
- Section C.2.9. End of life criteria - Edited discussion and list of factors considered.
- Section C.3. Selection of generation dispatch used in DEV Power Flow Studies - New section.
- Section E Nuclear plant interface coordination:
  - E.3. Design Requirements – Removed tables of NPIR voltage limits, voltage drops, and contingency scenarios.
  - E.7. Changes to the system – Simplified content to contain only the NUC-001-2, R8 quotation.

Details for Revision 16.0

- Table 1A, Note B: Deleted specific reference to 230 kV (table applies to several voltages).
- Table 1B, Notes F & G: Removed specific references to 500 kV (500 kV is inherent to this table).

FERC Form 715

Part 5 – Transmission Planning Assessment Practices

Virginia Electric & Power CO (VEPCO)
FERC Form 715
Part V – Transmission Planning Assessment Practices

General procedures to assess the transmission system:

Base case parameters for the conditions under study are established. The most common situation studied is the projected peak load, summer peak and winter peak, for a particular year. Studies at other than peak loads, off-peak and light load conditions, are also conducted. Loads, generation dispatch, power interchange, and system improvements are modeled in the base case for the year and conditions under study. These models are developed to represent the composite transmission/generation system into the future, although not for every year or season.

Such studies analyze the effect of single contingency outages of transmission lines, transformers, and generation units. In addition, the effects of less probable contingencies are also analyzed. These less probable contingencies involve outages such as loss of all generating units at a station, loss of all transmission lines on a common right-of-way, and other events resulting in loss of two or more components. If violations of the Planning Criteria are identified by the studies, alternative solutions are developed and analyzed. The recommended alternative plan then becomes part of the 10-year Transmission Plan. Similar studies are also conducted by PJM in the process of developing the PJM Regional Transmission Expansion Plan (RTEP).

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.

In performing such studies, VEPCO follows the practices outlined in the NERC Reliability Standards, PJM Planning Criteria, and the VEPCO Transmission Planning Criteria described in Part IV.

FERC Form 715

Part 6 – Evaluation of Transmission System Performance

As Virginia Electric and Power Company's most recently filed FERC Form 715 was filed by PJM, Part 6 to the Form 715 is not specific to the Company, and is therefore not being provided with the Company's 2020 IRP submittal