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May 1, 2018

VIA HAND DELIVERY

Joel H. Peck, Clerk
Document Control Center
State Corporation Commission
1300 E. Main Street, Tyler Bldg., 1st Fl.
Richmond, VA 23219

Commonwealth of Virginia ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's Integrated Resource Plan
filing pursuant to Va. Code § 56-597 et seq.
Case No. PUR-2018-00065

Dear Mr. Peck:

Please find enclosed for filing in the above-referenced matter an unbound original and fifteen (15) copies of the *Motion of Virginia Electric and Power Company for Entry of a Protective Order* (the "Motion"). A proposed Protective Order is included as Attachment 1 to the Motion.

Please do not hesitate to contact me if you have any questions in regard to this filing.

Very truly yours,

Vishwa B. Link

Vishwa B. Link

Enclosure

cc: William H. Chambliss, Esq.
Ashley B. Macko, Esq.
C. Meade Browder, Jr., Esq.
Lisa S. Booth, Esq.
Audrey T. Bauhan, Esq.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, *ex rel.*)
)
STATE CORPORATION COMMISSION)
) Case No. PUR-2018-00065
In re: Virginia Electric and Power Company's)
Integrated Resource Plan filing pursuant to)
Va. Code § 56-597 *et seq.*)

MOTION OF VIRGINIA ELECTRIC AND POWER COMPANY
FOR ENTRY OF A PROTECTIVE ORDER

Virginia Electric and Power Company (the "Company"), by counsel, hereby moves the State Corporation Commission of Virginia (the "Commission") for Entry of a Protective Order ("Motion") pursuant to Rules 110 and 170 of the Commission's Rules of Practice and Procedure (the "Procedural Rules"),[1] 5 VAC 5-20-110 and 5 VAC 5-20-170. In support thereof, the Company respectfully states as follows:

1. Pursuant to § 56-597 *et seq.* of the Code of Virginia, the Commission's Order Establishing Guidelines for Developing Integrated Resource Plans issued on December 23, 2008 in Case No. PUE-2008-00099,[2] and the Integrated Resource Planning Guidelines established therein, the Company is filing coincident with this Motion its total system Integrated Resource Plan (the "2018 Plan").

2. Rule 170 of the Procedural Rules authorizes the Commission or Hearing Examiner to issue an appropriate protective order or ruling establishing procedures applicable to

[1] 5 VAC 5-20-10 *et seq.*
[2] *Commonwealth of Virginia ex rel. State Corporation Commission Concerning Electric Utility Integrated Resource Planning Pursuant to §§ 56-597 et seq. of the Code of Virginia*, Case No. PUE-2008-00099, 2008 S.C.C. Ann. Rept. 606, Order Establishing Guidelines for Developing Integrated Resource Plans (Dec. 23, 2008).

the use of confidential information, including extraordinarily sensitive information, in a proceeding. Further, Rule 170 of the Procedural Rules directs an applicant to file confidential information under seal simultaneously with a motion for protective order or other confidential treatment. Coincident with the filing of this Motion, the Company has filed the confidential version of its 2018 Plan with the Commission under seal under separate cover.

3. The Company's 2018 Plan contains, at points so designated therein, confidential information that is being filed under seal and subject to this Motion. Because portions of the Company's 2018 Plan contain such confidential information, and because during the course of this proceeding confidential information may be provided to the Commission Staff or other parties in response to interrogatories or requests for production of documents or things, in compliance with Rule 170 of the Procedural Rules, the Company is filing this Motion to request the Commission enter a Protective Order. A proposed form of Protective Order is set forth in <u>Attachment 1</u> to this Motion, which includes an Attachment A thereto to address the treatment of confidential information in this proceeding.

4. The proposed Protective Order set forth in <u>Attachment 1</u> is substantially similar to the Protective Ruling issued by the Hearing Examiner in Case No. PUR-2017-00051 on June 14, 2017,[3] notwithstanding specific references to issues presented in that particular proceeding.

5. As permitted by 5 VAC 5-20-170, the proposed Protective Order recognizes that certain information or documents may contain extraordinarily sensitive information requiring additional protection from disclosure to competitors and provides that protection for such information and documents will be addressed on a case-by-case basis.

[3] *Commonwealth of Virginia ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2017-00051, Hearing Examiner's Protective Ruling (Jun. 14, 2017).

WHEREFORE the Company respectfully requests that the Commission grant its Motion for Entry of a Protective Order by issuing a Protective Order as set forth in Attachment 1 to this Motion, including Attachment A thereto, for use in this proceeding.

Respectfully submitted,

By: ______________________
Counsel

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Counsel for Virginia Electric and Power Company

May 1, 2018

CERTIFICATE OF SERVICE

I hereby certify that on this 1st day of May 2018, a true and accurate copy of the foregoing filed in Case No. PUR-2018-00065 was hand delivered or mailed first class, postage pre-paid, to the following:

C. Meade Browder, Jr., Esq.
Office of the Attorney General
Division of Consumer Counsel
202 North Ninth Street
Richmond, VA 23219

Attachment 1

180510038

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, *ex rel.*	)	
	)	
STATE CORPORATION COMMISSION	)	
	)	Case No. PUR-2018-00065
In re: Virginia Electric and Power Company's	)	
Integrated Resource Plan filing pursuant to	)	
Va. Code § 56-597 *et seq.*	)	

PROTECTIVE ORDER

On May 1, 2018, Virginia Electric and Power Company (the "Company"), by counsel, filed with the State Corporation Commission of Virginia ("Commission") its total system Integrated Resource Plan (the "2018 Plan") pursuant to § 56-597 *et seq.* of the Code of Virginia, the Commission's Order Establishing Guidelines for Developing Integrated Resource Plans issued on December 23, 2008 in Case No. PUE-2008-00099,[1] and the Integrated Resource Planning Guidelines established therein. Concurrent with its 2018 Plan, the Company filed a Motion for Entry of a Protective Order ("Motion") along with a proposed Protective Order ("Proposed Protective Order") setting forth the procedures by which confidential or proprietary information and documents shall be handled generally in this proceeding. In its Motion, the Company indicated that the Proposed Protective Order is substantially similar to the Protective Ruling issued by the Hearing Examiner in Case No. PUR-2017-00051 on June 14, 2017,[2] notwithstanding specific references to issues presented in that particular proceeding.[3]

---

[1] *Commonwealth of Virginia ex rel. State Corporation Commission Concerning Electric Utility Integrated Resource Planning Pursuant to §§ 56-597 et seq. of the Code of Virginia*, Case No. PUE-2008-00099, 2008 S.C.C. Ann. Rept. 606, Order Establishing Guidelines for Developing Integrated Resource Plans (Dec. 23, 2008).

[2] *Commonwealth of Virginia ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2017-00051, Hearing Examiner's Protective Ruling (Jun. 14, 2017).

[3] Motion at ¶ 4.

UPON CONSIDERATION of the Company's Motion and the Rules of Practice and Procedure,[4] the Commission finds that, to facilitate the filing and exchange of confidential information, and to permit the development of all issues in this proceeding, the Company's Motion should be granted and a Protective Order should be entered. The Protective Order herein adopts the substantive provisions of the Proposed Protective Order submitted by the Company. Accordingly,

IT IS DIRECTED THAT the following procedures shall be established for the filing, exchange, and handling of confidential information and documents in this case:

(1) Any documents, materials and information to be filed with or delivered to the Commission or produced by any party to Staff or another party, including transcripts, which the producing party designates and clearly marks as confidential or as containing trade secrets, privileged, or confidential commercial or financial information ("Confidential Information"), shall be filed, produced, examined, and used only in accordance with the conditions set forth below. Information that is available to the public anywhere else will not be granted confidential treatment and shall not be designated as "Confidential Information" by any party.

(2) Parties shall clearly mark and file under seal with, or deliver to, the Commission all information otherwise required to be filed or delivered but considered by the party to be Confidential Information. Items filed or delivered under seal shall be securely sealed in an opaque container that is clearly labeled "UNDER SEAL" and, if filed, shall meet the other requirements for filing contained in the Commission's Rules. An original and fifteen (15) copies of all such information shall be filed with the Clerk of the Commission and one (1) additional copy of all such information shall also be delivered under seal to the Staff counsel assigned to

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[4] 5 VAC 5-20-10 *et seq.*

the matter.

(3) Parties shall also file with, or deliver to, the Commission an original and one (1) copy of an expurgated or redacted version of all such documents containing Confidential Information for use and review by the public. On every document filed or delivered under seal as containing some Confidential Information, the producing party shall mark each individual page of the document that contains such Confidential Information, and shall clearly indicate the specific information requested to be treated as confidential by the use of highlighting, underscoring, bracketing or other appropriate marking. All remaining materials on each page of the document shall be treated as non-confidential and available for public use and review, as well as introduction at any hearing without regard to the remaining procedures established by this Protective Order. If an entire document is confidential, or if all information provided in electronic format is confidential, a marking prominently displayed on the first page of such document, or at the beginning of any information provided in electronic format, indicating that the entire document is confidential, shall suffice.

(4) If information that is requested pursuant to a discovery request in this proceeding is considered by the producing party to be Confidential Information, the producing party shall clearly mark all Confidential Information produced to Staff or other individuals authorized under this Protective Order to receive Confidential Information.

(5) Confidential Information from this proceeding that is retained by an attorney pursuant to Paragraph (17) (a), below, is not precluded from use in a subsequent Commission proceeding (if otherwise relevant and admissible), but shall remain subject to this Protective Order and any future order or ruling related thereto. Otherwise, all Confidential Information filed or produced by a party shall be used solely for the purpose of this proceeding (including

any appeals).

(6) Access to Confidential Information shall be provided and specifically limited to Staff and any party, their counsel and expert witnesses, and to support personnel working on this case or a future case, subject to the conditions in Paragraphs (5), (17) (a), and (17) (b), under the supervision of said counsel or expert witnesses and to whom it is necessary that the Confidential Information be shown for the purpose of this or a future proceeding, provided each such person granted access has previously executed an Agreement to Adhere to Protective Order ("Agreement"), which is set forth as <u>Attachment A</u> to this Protective Order. Staff and Staff counsel are not required to sign the Agreement, but are hereby ordered to preserve the confidentiality of the Confidential Information. All Agreements shall be promptly forwarded to the producing party and Staff counsel, and filed with the Clerk of the Commission upon execution.

(7) Staff or any party to the proceeding may challenge the confidential designation of particular information by filing a motion promptly with the Commission. The Commission or Hearing Examiner will conduct an *in camera* review of the challenged documents, materials or information. Upon challenge, the information shall be treated as confidential pursuant to the Rules only where the party requesting confidential treatment can demonstrate to the satisfaction of the Commission that the risk of harm of publicly disclosing the information outweighs the presumption in favor of public disclosure. In no event shall any party disclose the Confidential Information it has received subject to this Protective Order absent a finding by the Commission or Hearing Examiner that such information does not require confidential treatment.

(a) Within five (5) business days of the filing of the motion, the party requesting confidential treatment shall file a response. The response shall respond to each and every document and all information that is subject to the party's motion. The response shall: (1) describe each document and all information, such description to include the character and contents of each document and all information to the extent reasonably possible without disclosing the Confidential Information; (2) explain in detail why the information requires confidential treatment; and (3) describe and explain in detail the anticipated harms that might be suffered as a result of the failure of the document to be treated as confidential.

(b) Within three (3) business days of the filing of the response, the party objecting to confidential treatment may file a reply.

(c) Upon a determination by the Commission or the Hearing Examiner that all or portions of any materials filed under seal are not entitled to confidential treatment, the filing party shall file an original and one (1) copy of the redacted version of the document reflecting the determination.

(8) The Commission or the Hearing Examiner may challenge, *sua sponte*, the confidential designation of particular information at any time during the proceeding. If prior to the hearing, the Hearing Examiner challenges the confidential designation of particular information, the Hearing Examiner shall issue a ruling directing the party requesting confidential treatment to demonstrate that the risk of harm of publicly disclosing the information outweighs the presumption in favor of public disclosure. The Hearing Examiner will conduct an *in camera* review of the challenged documents, materials or information. The party requesting confidential treatment shall submit a response as directed by the Hearing Examiner. The response shall respond to each and every document and all information that is subject to the ruling. The response shall: (1) explain in detail why the information requires confidential treatment; and (2)

describe and explain in detail the anticipated harms that might be suffered as a result of the failure of the document to be treated as confidential. In no event shall any party disclose the Confidential Information it has received subject to this Protective Order absent a finding by the Hearing Examiner or the Commission that such information does not require confidential treatment.

(9) In the event that Staff or any other party seeks permission to grant access to any Confidential Information to any person other than a person authorized to receive such information under Paragraph (6) above, Staff or the party desiring permission shall first obtain the consent of counsel for the producing party. In the event of a negative response, Staff or the party seeking disclosure permission may file a motion with the Commission for such permission and shall bear the burden of proving the necessity for such disclosure.

(10) The producing party shall be under no obligation to furnish Confidential Information to persons other than those authorized to receive such information under Paragraph (6) above unless specifically ordered otherwise by the Commission or Hearing Examiner. Parties are encouraged to seek consent to disclose information or documents designated as confidential from the producing party to the maximum extent practicable before filing a motion pursuant to Paragraph (9) above.

(11) The Clerk of the Commission is directed to maintain under seal all documents, materials and information filed with the Commission in this proceeding that the producing party has designated as Confidential Information until further Order of the Commission or Hearing Examiner Ruling.

(12) A producing party is obligated to separate to the fullest extent practicable non-confidential documents, materials and information from Confidential Information and to

provide the non-confidential documents, materials and information without restriction.

(13) To the extent that a party contends that the terms of this Protective Order do not provide sufficient protection to prevent harm to the producing party or to others, the party may request additional protection for extraordinarily sensitive information by filing a motion with the Commission, pursuant to 5 VAC 5-20-110 and 5 VAC 5-20-170. The moving party shall also file such extraordinarily sensitive information with the Clerk of the Commission under seal and deliver a copy of the information to Staff counsel under seal, pursuant to Paragraph (2) above. The producing party has the burden to demonstrate to the satisfaction of the Commission that this Protective Order does not provide the extraordinarily sensitive information sufficient protection and that the proposed restrictions are necessary.

(a) The motion shall: (1) describe each document and all information for which additional protection is sought, such description to include the character and contents of each document and all information to the extent reasonably possible without disclosing the Confidential Information; (2) explain in detail for each document and all information why the confidential treatment afforded under this Protective Order is not sufficient to protect the producing party's interests; (3) describe and explain in detail the anticipated harms that might be suffered if the information is not afforded the higher protection; and (4) explain its proposed additional restrictions and why such restrictions are the minimum necessary to protect that party.

(b) Within three (3) business days of the filing of the motion, Staff and any party may file a response to the motion.

(c) Within two (2) business days of the filing of any response, the producing party may file a reply.

(14) In the event the Staff or any other party seeks to use Confidential Information in filed pleadings, testimony, or other documents, Staff or the party seeking such introduction shall:

(a) file both confidential and non-confidential versions of the pleading, testimony, or other document. Confidential versions of the filed pleadings, testimony, or other documents shall clearly indicate the confidential material, including extraordinarily sensitive information, if any, contained within by highlighting, underscoring, bracketing, or other appropriate marking;

(b) submit the confidential version to the Clerk of the Commission securely sealed in an opaque container that is clearly labeled "UNDER SEAL." Non-confidential versions of filed pleadings, testimony, or other documents shall redact all references to the Confidential Information. The filed pleadings, testimony, or other documents containing the Confidential Information shall be kept under seal unless and until the Commission rules to the contrary. Each party having signed Attachment A hereof, Staff, and each party to whom the Confidential Information belongs shall receive a copy of those parts of the filed pleadings, testimony, or other documents that contain references to or portions of the designated Confidential Information; provided, however, that a party shall not be entitled to receive an unredacted copy of filed pleadings, testimony, or other documents that include extraordinarily sensitive information for which additional protective treatment has been provided for by Order of the Commission or Hearing Examiner Ruling, unless such party otherwise has been provided access to such information contained in such filed pleadings, testimony, or other documents by such Order or Ruling. Each party having signed Attachment A hereof and Staff shall be bound by the Protective Order insofar as it restricts the use of and granting of access to the

Confidential Information and by any such Order or Ruling providing additional protections for the extraordinarily sensitive information.

(15) Oral testimony regarding Confidential Information, if ruled admissible by the Commission, will be taken *in camera* and in the presence of only Staff and those other persons who have been granted access to such specific Confidential Information pursuant to this Protective Order. That portion of the transcript recording such testimony shall be placed in the record under seal.

(16) No person authorized under this Protective Order to have access to Confidential Information shall disseminate, communicate, or reveal any such Confidential Information to any person not specifically authorized under this Protective Order to have access to the same.

(17) (a) Attorneys may retain Confidential Information contained in their notes, other work product, and documents that are part of the record in this proceeding (including, but not limited to, transcripts, testimony exhibits, pleadings, rulings, and orders), provided that Confidential Information contained therein must continue to be treated as directed by this Protective Order.

(b) If not covered by (a), above, at the conclusion of this proceeding (including any appeals), any originals or reproductions of any Confidential Information produced pursuant to this Protective Order shall be returned to the producing party or destroyed. In addition, at such time, any notes, analysis or other documents prepared containing Confidential Information shall be destroyed. At such time, any originals or reproductions of any Confidential Information, or any notes, analysis or other documents prepared containing Confidential Information in Staff's possession, will be returned to the producing party, destroyed or kept with Staff's permanent work papers in a manner that will preserve the confidentiality of the

Confidential Information. The producing party shall also retain all Confidential Information for a period of at least five (5) years after the conclusion of this proceeding (including any appeals). Insofar as the provisions of this Protective Order restrict the communications and use of the Confidential Information produced thereunder, such restrictions shall continue to be binding after the conclusion of this proceeding (including any appeals) as to the Confidential Information.

(18) Any party or person who obtains Confidential Information and thereafter fails to reasonably protect or misuses it in any way shall be subject to sanctions as the Commission may deem appropriate, including the penalties provided for in § 12.1-33 of the Code of Virginia. This provision is not intended to limit the producing party's rights to pursue any other legal or equitable remedies that may otherwise exist.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, *ex rel.*	)	
	)	
STATE CORPORATION COMMISSION	)	
	)	Case No. PUR-2018-00065
In re: Virginia Electric and Power Company's	)	
Integrated Resource Plan filing pursuant to	)	
Va. Code § 56-597 *et seq.*	)	

AGREEMENT TO ADHERE TO PROTECTIVE ORDER
PROVIDING FOR CONFIDENTIAL TREATMENT

I, ________________, on behalf of and representing ________________, hereby acknowledge having read and understood the terms of the Protective Order entered in this proceeding on ____________, 2018, and agree to treat all Confidential Information that I receive in connection with Case No. PUR-2018-00065 as set forth in that Protective Order. Such treatment shall include, but not be limited to: (1) not disseminating, communicating or revealing any Confidential Information to any person, other than Staff, not specifically authorized to receive Confidential Information under that Protective Order; (2) if an attorney licensed to practice law in Virginia, admitted *pro hac vice* in this case, or employed as corporate counsel, returning or destroying all Confidential Information produced pursuant to that Protective Order except for the attorney's notes and work product, and documents that are part of the record in this proceeding (including, but not limited to, transcripts, testimony, exhibits, pleadings, rulings, and orders); and (3) if not covered by (2), above, returning or destroying all Confidential Information produced pursuant to that Protective Order.

____
Signature

____
Printed Name

____
On behalf of

____
Date

part 2

4.4 COMMODITY PRICE ASSUMPTIONS

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analysis in this 2018 Plan using energy and commodity price forecasts provided by ICF in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, and power prices rely on forward market prices as of December 29, 2017, 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 prices are provided by ICF for all years forecasted within this 2018 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM Base Residual Auction through the 2020/2021 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2021/2022 delivery year.

The key assumptions on market structure and the use of an integrated, internally-consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecasts. In the 2018 Plan, the Company utilizes three commodity forecasts to evaluate the Plan(s). The three forecasts used in the Plan are the Federal CO_2 commodity forecast, the No CO_2 Tax commodity forecast, and the Virginia RGGI commodity forecast.

4.4.1 FEDERAL CO_2 COMMODITY FORECAST

The Federal CO_2 commodity forecast was developed for the Company to address a future market environment where carbon regulations affect electric generation plants. The Company utilized this commodity forecast in the analysis of Plan E. Utilizing the Federal CO_2 commodity forecast allows the Company to evaluate Plan E using a commodity price forecast that reflects ICF's independent view of future market conditions including potential regulations on carbon emissions from electric generation activities. ICF's independent internal views of key market drivers include: (i) market structure and policy elements that shape allowance; (ii) fuel and power markets ranging from expected capacity and pollution control installations; (iii) environmental regulations; and (iv) fuel supply-side issues. The development process assesses the impact of environmental regulations on the power and fuel markets and incorporates ICF's latest views on the outcome of new regulatory initiatives. The Federal CO_2 commodity forecast provides prices for fuel, energy, capacity, emission allowances, and RECs.

In the Federal CO_2 commodity forecast, the assumptions for CO_2 regulation represent a probability weighted outcome of legislative and regulatory initiatives, including the possibility of no regulatory program addressing CO_2 emissions. A charge on CO_2 emissions from the power sector is assumed to begin in 2026.

The Federal CO_2 commodity forecast considers three potential outcomes. The first possible outcome considers a $0/ton CO_2 price; the second possible outcome considers a tradable mass-based program (i.e., limit on tonnage of CO_2 emissions) on existing and new sources; and a third possible outcome considers a more stringent legislative approach.

The $0/ton price under the first possible outcome can be thought of as either no-program or a "behind-the-fence" requirement without a market-based CO_2 price.

The second possible outcome is considered a "mid" case approach to carbon regulation that reflects a delay in the implementation of the CPP. While it is likely that a replacement for the CPP promulgated under a future regulation would include different requirements, ICF relies 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 regional trading structure. It assumes that California and RGGI states address leakage by including new sources, while remaining regions only include existing sources and address leakage through alternative measures.

This representation also assumes RGGI and the California-specific programs continue as individual programs.

The third possible outcome—a "high" case approach—assumes 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 levels being discussed by several states, and it is consistent with what was proposed under the Waxman-Markey Bill. 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 2030, the Federal CO_2 commodity forecast assumed a 40% probability for the $0/ton outcome, a 50% probability of a "mid" case type program and a 10% probability for the "high" case legislative mass cap based program. By 2040, the probability of a CO_2 price by means of the mid and high case programs increases to 85%. The resulting CO_2 price forecast rises from a little over $3.50/ton (nominal $) in 2030 to over $20/ton in 2040 in the Federal CO_2 commodity forecast.

Comparisons of the Federal CO_2 commodity forecast used in this 2018 Plan and the CPP commodity forecast used in the 2017 Plan are provided below. Figures 4.4.1.1 through 4.4.1.5 display the fuel price forecasts, while Figure 4.4.1.6 displays the forecasted price for SO_2 and NO_x on a dollar per ton basis. Figure 4.4.1.7 displays CO_2 emissions allowances ($/ton). Figures 4.4.1.8 and 4.4.1.9 present the forecasted market clearing price for peak and off peak power prices for the DOM Zone. The PJM RTO capacity price forecast is presented in Figure 4.4.1.10. Appendix 4B provides delivered fuel prices and primary fuel expense from the PLEXOS model output using the Federal CO_2 commodity forecast.

Figure 4.4.1.1 – Fuel Price Forecasts - Natural Gas Henry Hub

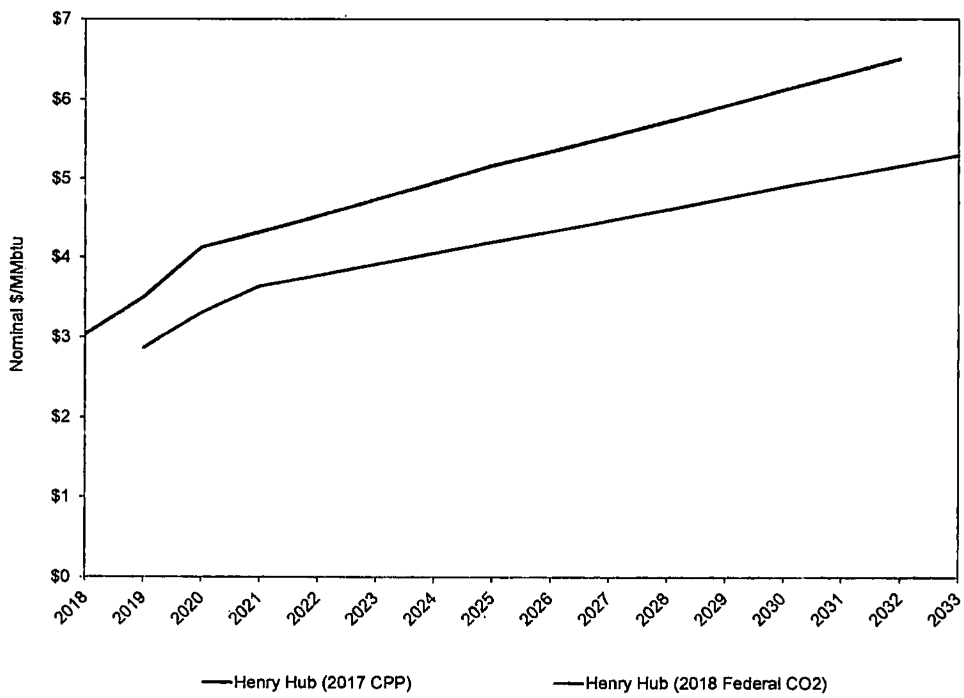

Figure 4.4.1.2 – Fuel Price Forecasts - Natural Gas DOM Zone

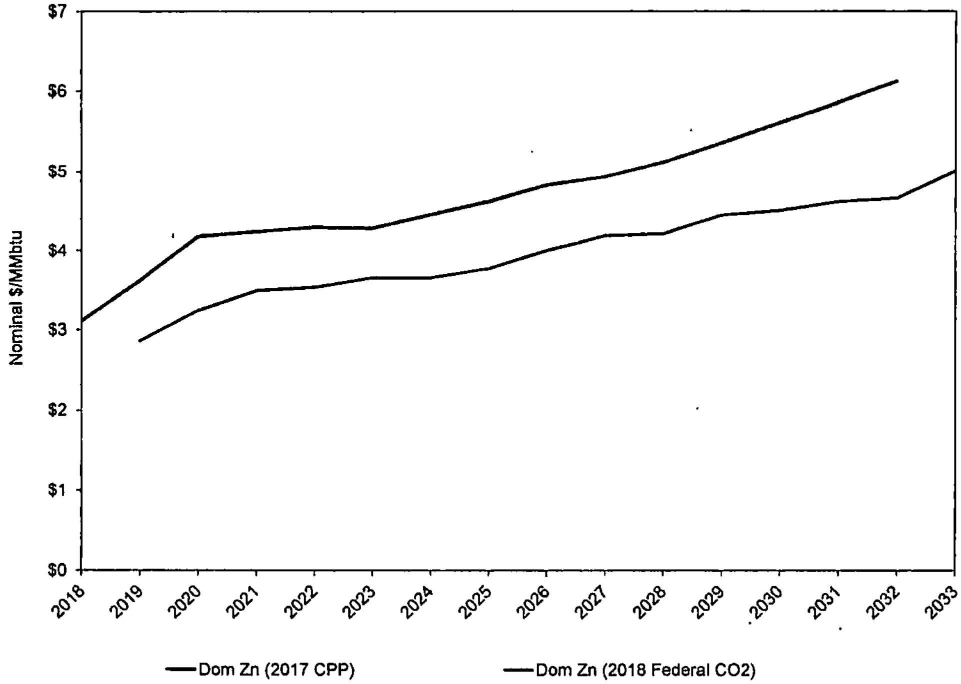

Figure 4.4.1.3 – Fuel Price Forecasts - Coal

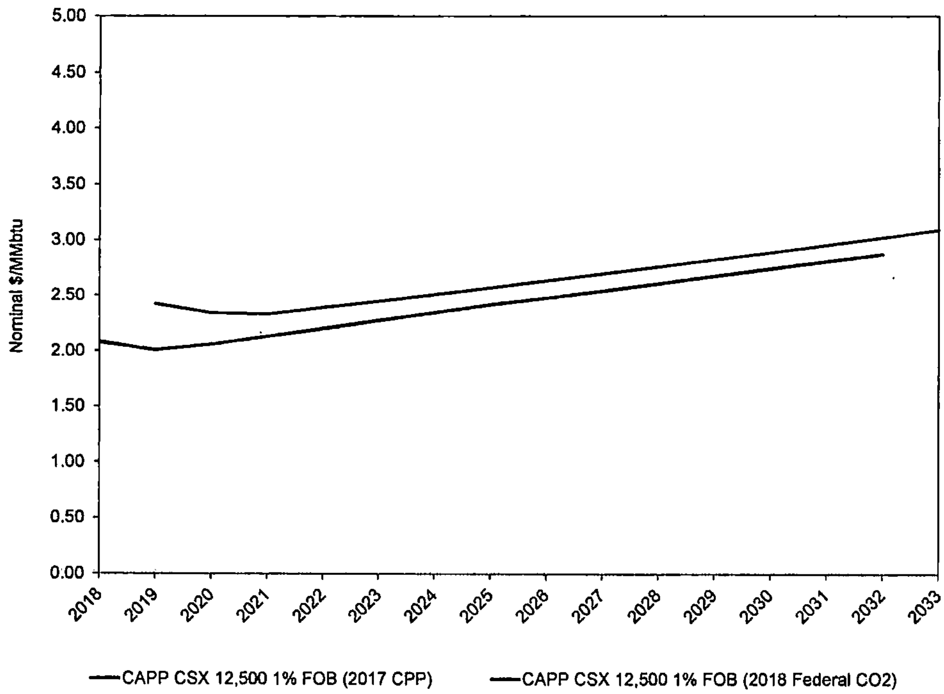

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Figure 4.4.1.4 – Fuel Price Forecasts - #2 Oil

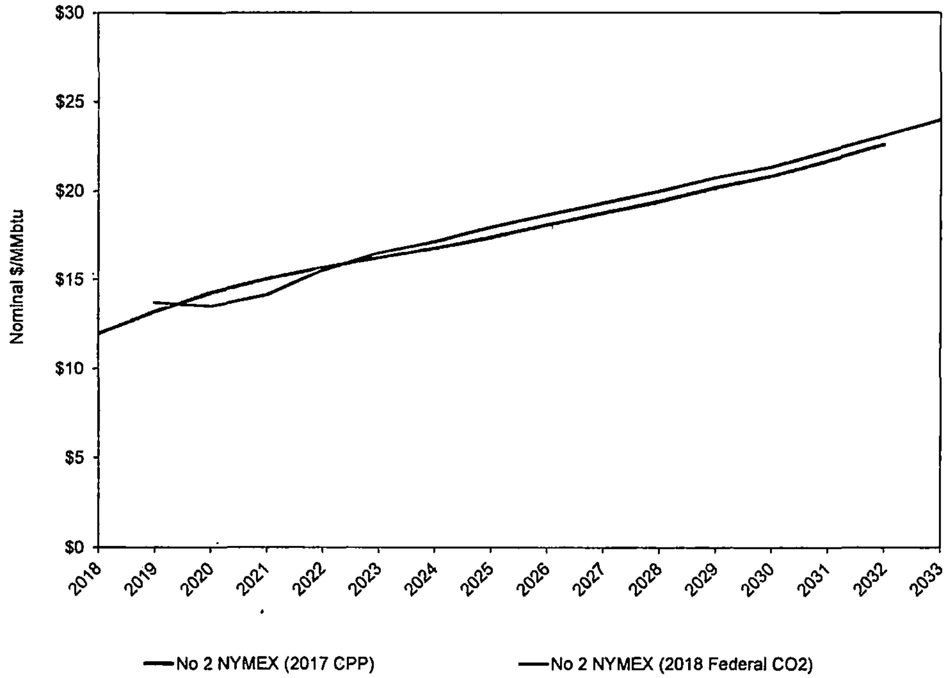


Figure 4.4.1.5 – Fuel Price Forecasts – #6 Oil

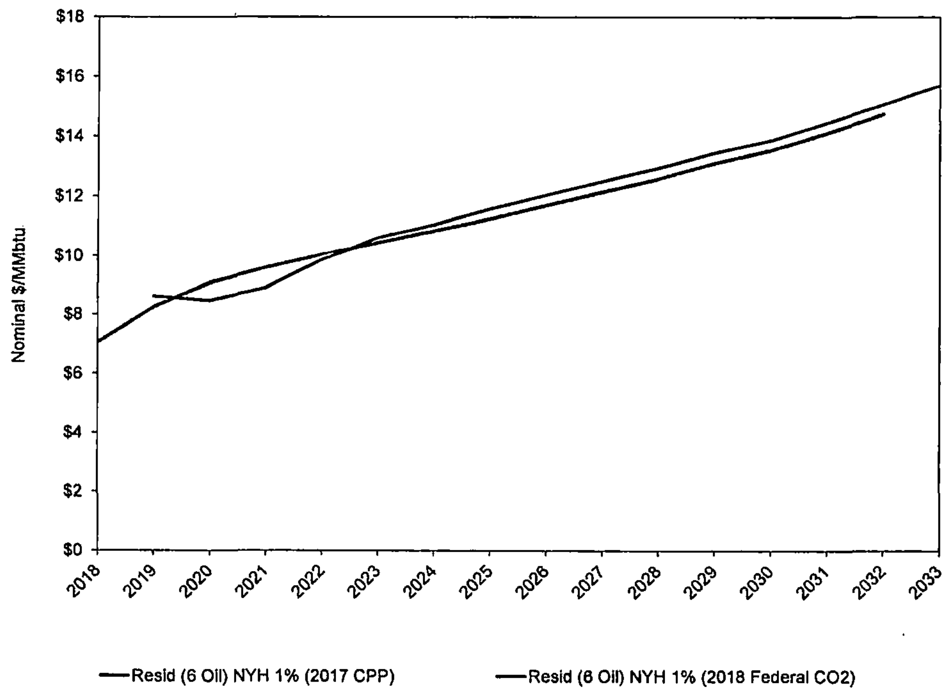


Figure 4.4.1.6 – Allowance Price Forecasts – SO_2 & NO_X

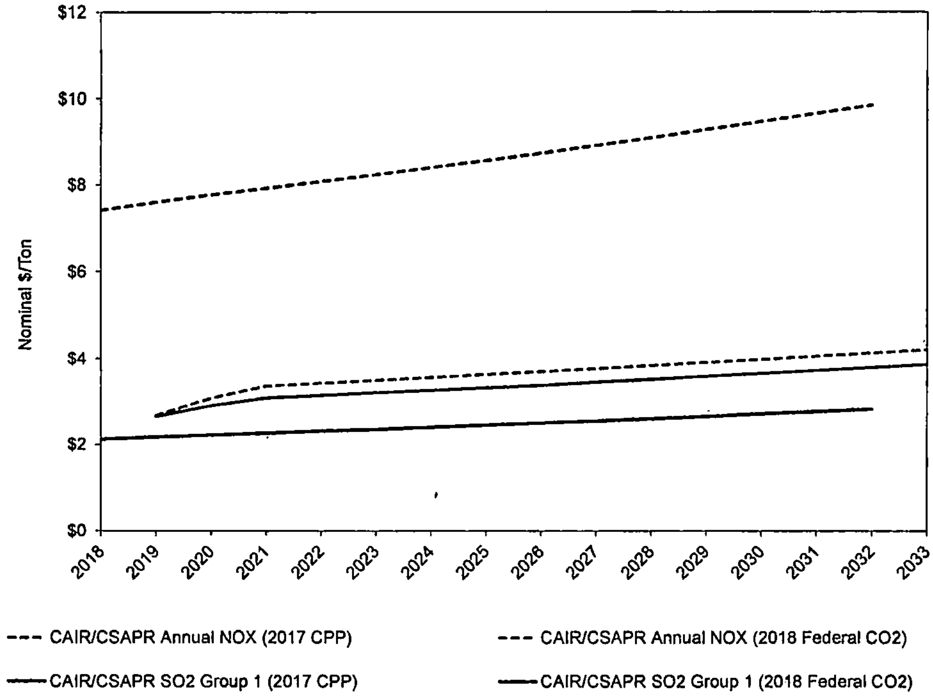
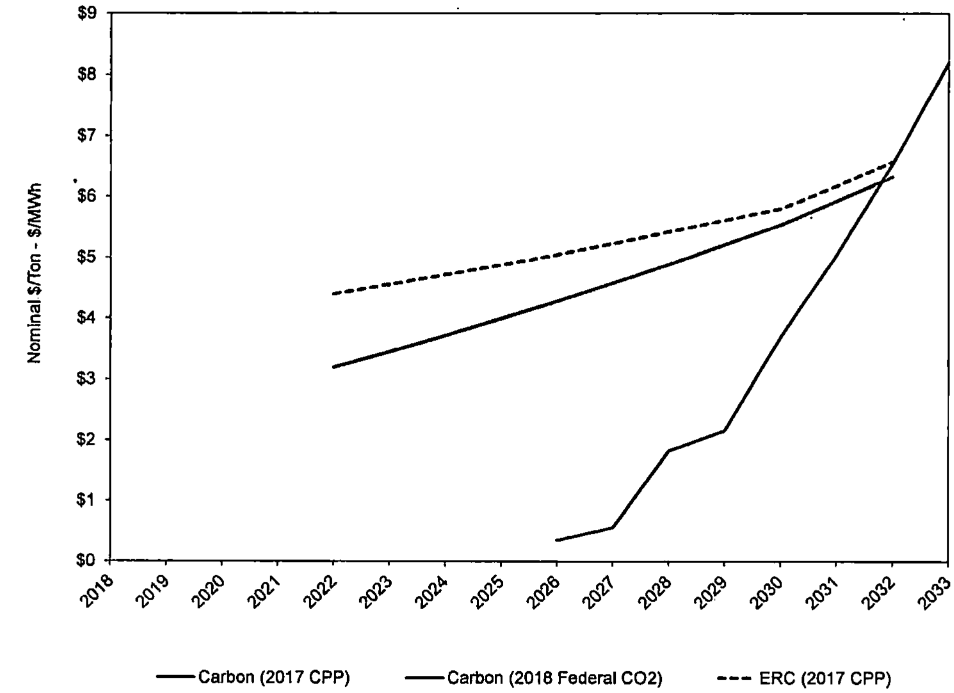


Figure 4.4.1.7 – Allowance Price Forecasts - CO_2



Note: The Federal CO_2 commodity forecast used in the 2018 Plan includes a CO_2 allowance price on a per ton basis. In the 2017 Plan, the commodity forecast modeled a CPP-type carbon regulation program. In such a program, there would be both emission rate credit forecast ($/MWh), which applies to states adopting an intensity-based compliance program, and a CO_2 allowance price forecast ($/ton), which applies to states adopting a mass-based compliance program. The Federal CO_2 commodity forecast did not include an emission rate credit forecast because it assumes that states will adopt mass-based compliance programs.

Figure 4.4.1.8 – Power Price Forecasts – On Peak

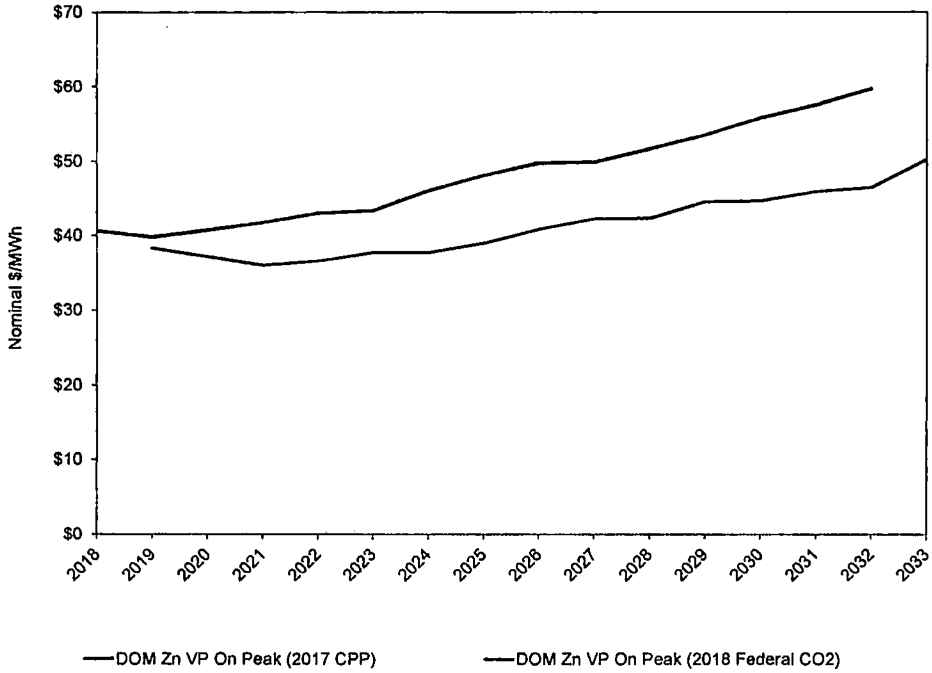


Figure 4.4.1.9 – Power Price Forecasts – Off Peak

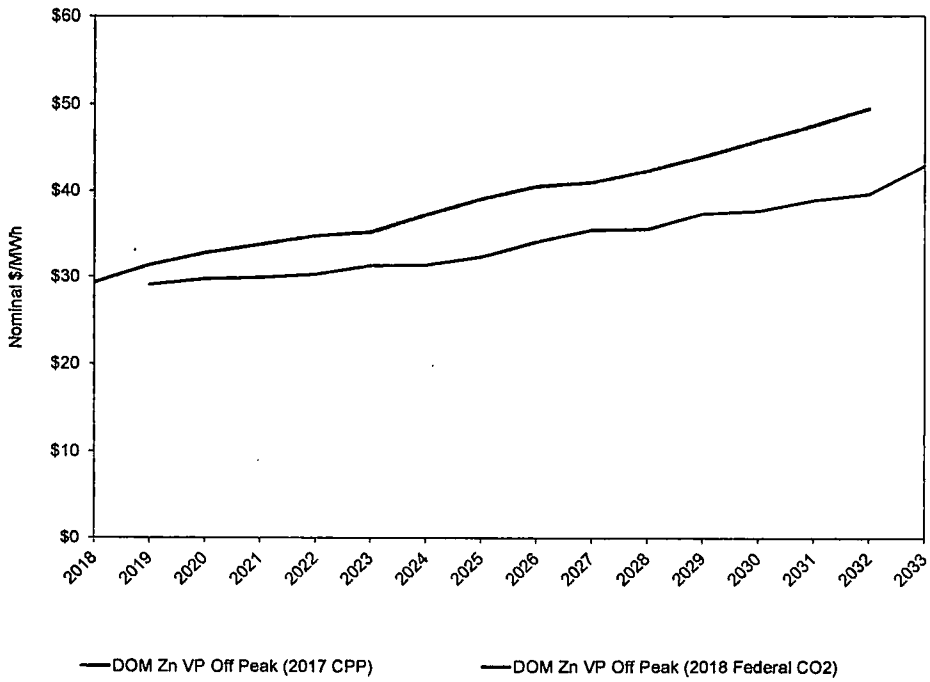
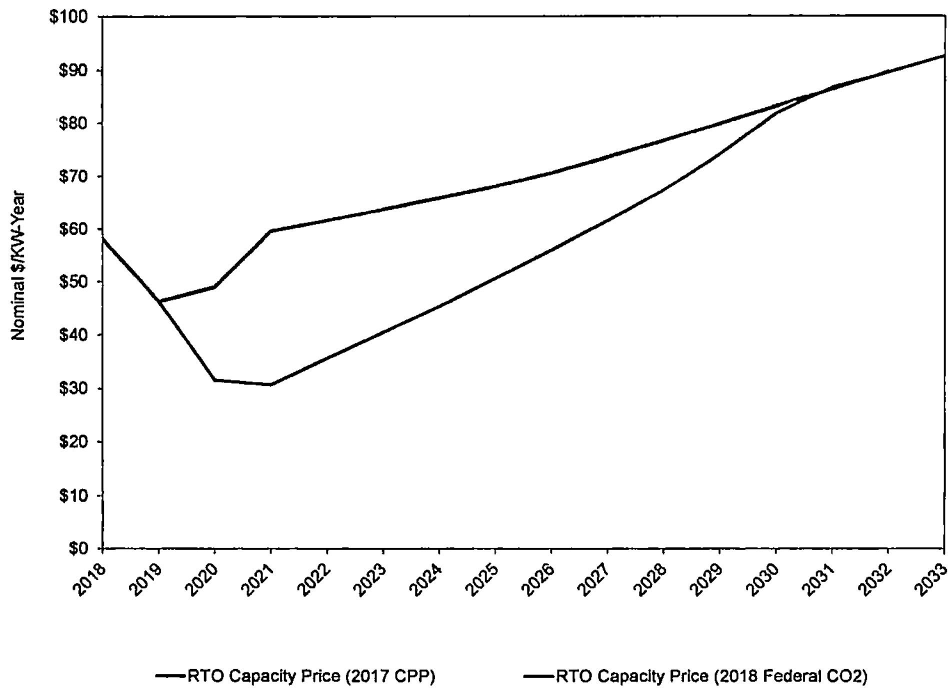


Figure 4.4.1.10 – PJM RTO Capacity Price Forecasts



The forecast of power and gas prices are lower this year than forecasted in the 2017 Plan. Lower power prices result from a combination of factors, most notably lower gas prices and lower load growth forecasts. Lower gas prices reflect the decrease in cost and increase in volume of the shale gas resources and, over the longer term, the revised assumption that nuclear units are likely to renew their licenses to 80 years. Capacity prices are also lower, reflecting the results of the last auction and the reduction of the assumed risk premium penalties. Figure 4.4.1.11 presents a comparison of average fuel, electric, and REC prices used in the 2017 Plan relative to those used in this 2018 Plan.

Figure 4.4.1.11 – 2017 Plan to 2018 Plan Fuel & Power Price Comparison

Fuel Price	Planning Period Comparison Average Value (Nominal $) 2017 Plan CPP Commodity Forecast [3]	2018 Plan Federal CO_2 Commodity Forecast [3]
Henry Hub Natural Gas[1] ($/MMbtu)	5.05	4.29
DOM Zone Delivered Natural Gas[1] ($/MMbtu)	4.71	3.99
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.41	2.66
No. 2 Oil ($/MMbtu)	17.48	18.52
1% No. 6 Oil ($/MMbtu)	11.22	11.93
PJM-DOM On-Peak ($/MWh)	48.05	41.29
PJM-DOM Off-Peak ($/MWh)	38.91	34.36
PJM Tier 1 REC Prices ($/MWh)	15.32	7.04
RTO Capacity Prices[2] ($/kW-yr)	68.79	59.33

Note: 1) DOM Zone natural gas price used as a representative gas price for Virginia. Henry Hub prices are shown to provide market reference.
2) Capacity price represents actual clearing price from PJM Reliability Pricing Model. Base Residual Auction results through power year 2019/2020 for the 2017 Plan and 2020/2021 for the 2018 Plan.
3) 2017 Planning Period 2018 – 2032, 2018 Planning Period 2019 – 2033.

4.4.2 ADDITIONAL COMMODITY PRICES

The alternative commodity price forecasts represent reasonable outcomes for future commodity prices based on alternate views of key fundamental drivers of commodity prices. However, as with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this Plan. History has shown that unforeseen events, and events not contemplated 5 or 10 years before their occurrence, can result in significant changes in market fundamentals. A recent example is the shale gas revolution that transformed the pricing structure of natural gas. Another recent example is the retirement of numerous, coal-fueled generation units, in response to low gas prices, an aging coal fleet, and environmental compliance cost.

The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in this 2018 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes. In this 2018 Plan, the Company has included a comprehensive risk analysis that provides a more robust assessment of possible price forecast outcomes. A description of this analysis is included in Chapter 6.

The Company utilizes the No CO_2 Tax commodity forecast to evaluate Plan A, which anticipates a future without any new regulations or restrictions on CO_2 emissions. In this forecast, the cost associated with carbon emissions is removed from the commodity forecast. DOM Zone peak energy prices are slightly lower than the Federal CO_2 commodity forecast across the Planning Period as there is no CO_2 cost to pass through to power prices. To be clear, the Company expects that some form of GHG regulations or legislation will occur and plans accordingly. The No CO_2 Tax forecast is only utilized in analysis of Plan A, which is used to measure the cost of GHG program compliance.

The Company utilizes the Virginia RGGI commodity forecast to evaluate Alternative Plans B, C, and D. The Virginia RGGI forecast assumes that Virginia joins RGGI (either directly or indirectly through the Virginia RGGI Program). The primary reason for developing this forecast was to allow the Company to evaluate the Alternative Plans compliant with Virginia RGGI or RGGI using a commodity price forecast that reflects Virginia linking to RGGI. The key assumptions on market structure and the use of an integrated, internally-consistent fundamental based modeling methodology remain consistent with those utilized in the Federal CO_2 commodity forecast except that the carbon program modeled is RGGI, which begins in 2020, and that there is no national program as used in the Federal CO_2 commodity forecast.

Appendix 4A provides the annual prices (nominal $) for the Federal CO_2 commodity forecast, the No CO_2 Tax commodity forecast, and the Virginia RGGI commodity forecast. Figure 4.4.2.1 provides a comparison of the Federal CO_2 commodity forecast, the No CO_2 Tax commodity forecast, and the Virginia RGGI commodity forecast.

Figure 4.4.2.1 – 2018 Plan Fuel & Power Price Comparison

	2019 - 2033 Average Value (Nominal $)		
Fuel Price	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
Henry Hub Natural Gas ($/MMbtu)	4.29	4.29	4.29
DOM Zone Delivered Natural Gas ($/MMbtu)	3.99	3.88	3.99
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.66	2.67	2.67
No. 2 Oil ($/MMbtu)	18.52	18.52	18.52
1% No. 6 Oil ($/MMbtu)	11.93	11.93	11.93
Electric and REC Prices			
PJM-DOM On-Peak ($/MWh)	41.29	41.12	40.63
PJM-DOM Off-Peak ($/MWh)	34.36	34.11	33.80
PJM Tier 1 REC Prices ($/MWh)	7.04	9.06	9.19
RTO Capacity Prices ($/kW-yr)	59.33	60.37	60.76

4.5 DEVELOPMENT OF DSM PROGRAM ASSUMPTIONS

The Company develops assumptions for new DSM programs by engaging vendors through a competitive bid 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.

The DSM program design process includes evaluating programs as either single measure, like the former Residential Heat Pump Upgrade Program, or multi-measure, like the Small Business Improvement Program. For all measures in a program, the design vendor develops a baseline for a standard customer end-use technology. The baseline establishes the current energy usage for a particular appliance or customer end-use. Next, assumptions for a more efficient replacement measure or end-use are developed. The difference between the more efficient energy end-use and the standard end-use provides the incremental benefit that the Company and customer will achieve if the more efficient energy end-use is implemented.

The program design vendor's development of assumptions for a DSM program include determining cost estimates for the incremental customer investment in the more efficient technology, the incentive that the Company should pay the customer to encourage investment in the efficient technology, and the program cost the Company will likely incur to administer the program. In addition to the cost assumptions for the program, the program design vendor develops incremental demand and energy reductions associated with the program. This data is represented in the form of a load shape for energy efficiency programs that identifies the energy reductions by hour for each hour of the year (8,760 hour load shape).

The Company then uses the program assumptions developed by the program design vendor to perform cost/benefit tests for the programs. 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.

4.6 TRANSMISSION PLANNING

The Company's transmission planning process, system adequacy, transfer capabilities, and transmission interconnection process are described in the following subsections. As used in this 2018 Plan, electric transmission facilities can be generally defined as those operating at 69 kV and above that provide for the interchange of power within and outside of the Company's system.

4.6.1 REGIONAL TRANSMISSION PLANNING & SYSTEM ADEQUACY

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.

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, an RTO responsible for the movement of wholesale electricity. PJM is registered with NERC as the Company's planning coordinator and transmission planner. Accordingly, the Company participates in the PJM regional transmission expansion plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a 5-year and a 15-year outlook.

The Company evaluates its ability to support expected customer growth through its internal transmission planning process. The results of this evaluation will indicate 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.

4.6.2 STATION SECURITY

As part of the Company's overall strategy to improve its transmission system resiliency and security, the Company continues to install additional physical security measures at substations and switching stations in Virginia and North Carolina. The Company announced these plans following the widely-reported April 2013 Metcalfe Substation incident in California.

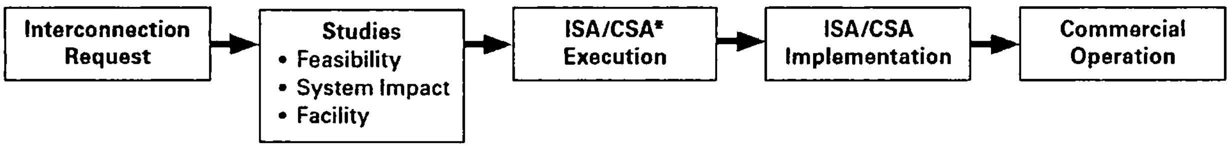
As one of the region's largest electricity suppliers, the Company formulated a plan to increase the security and resilience of its transmission substations and other critical infrastructure against man-made physical or cyber threats and natural disasters, and to procure mobile response equipment and stockpile crucial equipment for major damage recovery. These new security facilities will be installed in accordance with recently-approved NERC mandatory compliance standards. In addition, the Company has completed construction of its new System Operations Center, which was commissioned and became operational in August 2017.

4.6.3 TRANSMISSION INTERCONNECTIONS

For any new generation proposed within the Company's transmission system, either by the Company or by other parties, the generation owner files an interconnection request with PJM. PJM, in conjunction with the Company, conducts feasibility studies, system impact studies, and facilities studies to determine the facilities required to interconnect the generation to the transmission system (Figure 4.6.3.1). These studies ensure deliverability of the generation into the PJM market. The scope of these studies is provided in the applicable sections of PJM Manual 14A[25] and the Company's Facility Connection Requirements.[26]

The results of these studies provide the requesting interconnection customer with an assessment of the feasibility and costs (both interconnection facilities and network upgrades) to interconnect the proposed facilities to the PJM system, which includes the Company's transmission system.

Figure 4.6.3.1 - PJM Interconnection Request Process



Note: Projects may drop out of the queue at any time.

* Interconnection Service Agreement/Construction Service Agreement

Source: PJM

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

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

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

The Promod IV® model enables the Company to integrate the transmission and generation system planning to: (i) analyze the zonal and nodal level locational marginal pricing ("LMP") impact of new resources and transmission facilities; (ii) calculate the value of new facilities due to the alleviation of system constraints; and (iii) perform transmission congestion analysis. The model is utilized to determine the most beneficial location for new supply-side resources in order to optimize the future need for both generation and transmission facilities, while providing reliable service to all customers.

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

[26] The Company's Facility Connection Requirements are posted at https://www.dominionenergy.com/library/domcom/media/large-business/selling-power-to-dominion-energy/parallel-generation-and-interconnection/facility-connection-requirements.pdf.

The Promod IV® model evaluates the impact of resources under development that are selected by the PLEXOS model.

Historically, the Promod IV® and Power System Simulator for Engineering were utilized to evaluate the impact of future generation retirements on the reliability of the DOM Zone transmission grid. These evaluations are ongoing and not yet complete for the units identified as candidates for retirement and included in this 2018 Plan. At this stage, the Company has no definitive plans regarding any generating unit retirement.

4.7 GAS SUPPLY, ADEQUACY, & RELIABILITY

In maintaining its diverse generating portfolio, the Company manages a balanced mix of fuels that includes fossil, nuclear, and renewable resources. Specifically, the Company's fleet includes units powered by natural gas, coal, petroleum, uranium, biomass (waste wood), water, and solar. This balanced and diversified fuel management approach supports the Company's efforts in meeting its customers' growing demand by responsibly and cost-effectively managing risk. By avoiding overreliance on any single fuel source, the Company protects its customers from rate volatility and other harms associated with shifting regulatory requirements, commodity price volatility, and reliability concerns.

Electric Power and Natural Gas Interdependency

With a production shift from conventional to an expanded array of unconventional gas sources (such as shale) and relatively low commodity price forecasts, natural gas-fired generation continues to be a competitive choice for new capacity.

However, the electric grid's exposure to interruptions in natural gas fuel supply and delivery has increased with the generating capacity's growing dependence on a single fuel. 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 delivery 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. As the percentage of natural gas use increases in terms of both energy and capacity, the Company intends to increase its use of firm transport capacity to help ensure reliability and price stability.

Pipeline deliverability can impact 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 impact pipeline reliability. The sudden loss of a large efficient generator can cause 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.

As a result, the Company routinely assesses the natural gas-fueled reliability of its system. The results of these assessments show that current interruptions on any single pipeline are manageable.

But as the Company and the electric industry continue to shift to a heavier reliance on natural gas, additional actions are needed to ensure future reliability and rate stability. Additionally, equipping future gas-fired resources with backup fueling options may be needed to further enhance the reliability of the electric system.

System Planning

In general, electric transmission service providers maintain, plan, design, and construct systems that meet federally-mandated NERC Reliability Standards and other requirements, and that are capable of serving forecasted customer demands and load growth. A well-designed electrical grid, with numerous points of interconnection and facilities designed to respond to contingency conditions, results in a flexible, robust electrical delivery system.

In contrast, pipelines generally are constructed to meet new load growth. FERC does not authorize new pipeline capacity unless customers have already committed to it via firm delivery contracts, and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, in order for a pipeline to add or expand facilities, existing or new customers must request additional firm service. The resulting new pipeline capacity closely matches the requirements of the new firm capacity request. If the firm customers accept all of the gas under their respective contracts, little or no excess pipeline capacity will be available for interruptible customers. This is a major difference between natural gas pipeline infrastructure construction and electric transmission system planning—the electric system is expanded to address current or projected system conditions and the costs are typically socialized across customers.

Actions

The Company is aware of the risks associated with natural gas deliverability and has been proactive in mitigating these risks. For example, the Company continues to secure firm natural gas pipeline transportation service for all of the newer CC facilities, including the Bear Garden, Warren County, and Brunswick County Power Stations, as well as the Greensville County Power Station, which is currently under construction. As an additional example, the Company has executed a precedent agreement to secure firm transportation services on the Atlantic Coast Pipeline, which will supply natural gas to strategic points in the Company's service territory. Additionally, the Company maintains a portfolio of firm gas transportation to serve a portion of its remaining gas generation fleet.

CHAPTER 5 – FUTURE RESOURCES

5.1 FUTURE SUPPLY-SIDE RESOURCES

The Company continues to monitor and gather information about potential and emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including, but not limited to, planning, financial analysis, construction, operations, and business development. The dispatchable and non-dispatchable resources examined in this 2018 Plan are defined and discussed in the following subsections.

5.1.1 ASSESSMENT OF SUPPLY-SIDE RESOURCE ALTERNATIVES

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, the 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, operation, and maintenance. Figure 5.1.1.1 summarizes the resource types that the Company reviewed as part of this IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column.

Figure 5.1.1.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource
Aero-derivative CT	Peak	Yes	Natural Gas	Yes
Batteries	Peak	Yes	Varies	No
Biomass	Baseload	Yes	Renewable	Yes
CC 1x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 2x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 3x1	Intermediate/Baseload	Yes	Natural Gas	No
CFB	Baseload	Yes	Coal	No
Coal (SCPC) w/ CCS	Intermediate	Yes	Coal	Yes
Coal (SCPC) w/o CCS	Baseload	Yes	Coal	No
CT	Peak	Yes	Natural Gas	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes
Hydro Power	Intermittent	No	Renewable	No
IGCC CCS	Intermediate	Yes	Coal	Yes
IGCC w/o CCS	Baseload	Yes	Coal	No
Nuclear	Baseload	Yes	Uranium	Yes
Offshore Wind	Intermittent	No	Renewable	Yes
Onshore Wind	Intermittent	No	Renewable	Yes
Pumped Storage	Peak	Yes	Renewable	No
Reciprocating Engine CT	Peak	Yes	Natural Gas	No
Solar PV	Intermittent	No	Renewable	Yes
Solar PV w/Aero-derivative CT	Peak	Yes	Renewable	Yes
SMR	Baseload	Yes	Uranium	No

The resources not included as busbar resources for further analysis faced barriers such as the feasibility of the resource in the Company's service territory, the stage of technological development, and the availability of reasonable cost information. Although such resources were not considered in this 2018 Plan, the Company will continue monitoring all technologies that could best meet the energy needs of its customers.

5.1.2 DISPATCHABLE RESOURCES

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, 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-dispatch, renewable resources, such as solar and wind. This resource was considered for further analysis in the Company's busbar curve.

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 blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. 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. This resource was not considered for further analysis in the Company's busbar curve.

Biomass

Biomass generation facilities rely on renewable fuel in their thermal generation process. In the Company's service territory, the renewable fuel primarily used is waste wood. Greenfield biomass was considered for further analysis in the Company's busbar curve, but it was found to be uneconomic. Generally, biomass generation facilities are geographically limited by access to a fuel source.

Circulating Fluidized Bed

Circulating fluidized bed ("CFB") combustion technology is a clean coal technology that has been operational for the past few decades and can consume a wide array of coal types and qualities, including low British thermal unit ("Btu") waste coal and wood products.

The technology uses jets of air to suspend the fuel and results in a more complete chemical reaction allowing for efficient removal of many pollutants, such as NO_x and SO_2. The preferred location for this technology is within the vicinity of large quantities of waste coal. The Company will continue to track this technology and its associated economics based on site and fuel resource availability. With strict standards on emissions from the federal EGU New Source Performance Standards ("NSPS") rule along with the potential Virginia RGGI program, this resource was not considered for further analysis in the Company's busbar curve.

Coal with Carbon Capture and Sequestration[27]
Coal generating technology is very mature with hundreds of plants in operation across the United States. Carbon capture and sequestration ("CCS") is a developing technology designed to collect and trap CO_2 underground. This technology can be combined with many thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal-burning facilities. The targets for new EGUs under the federal EGU NSPS 111(b) rule, would require all new fossil fuel-fired electric generation resources to meet a strict limit for CO_2 emissions. To meet these standards, CCS technology is assumed to be required on all new coal facilities, including supercritical pulverized coal ("SCPC") and integrated-gasification combined-cycle ("IGCC") technologies. Coal generation with CCS technology, however, is still under development and not commercially available. The Company will continue to track this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve.

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

Gas-Fired Combined-Cycle
A natural gas-fired CC plant combines a CT and a steam turbine plant into a single, highly-efficient power plant. The Company considered CCs with heat recovery steam generators and supplemental firing capability based on commercially-available advanced technology. This resource was considered for further analysis in the Company's busbar curve.

Gas-Fired Combustion Turbine
Natural gas-fired CT technology has the lowest capital requirements ($/kW) of any resource considered; however, it has relatively high variable costs because of its low efficiency. This is a proven technology with cost information readily available. This resource was considered for further analysis in the Company's busbar curve.

IGCC with CCS[26]
IGCC 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. IGCC systems remove a greater proportion of other air effluents in comparison to traditional coal units. The Company will continue to follow this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve.

Nuclear
With a need for clean, non-carbon emitting baseload power, and with nuclear power's proven record of low operating costs, around the clock availability, and zero emissions, nuclear power generation units offer a feasible alternative to the electric sector. The process for constructing a new nuclear unit remains costly and time-consuming with various permits for design, location, and operation required by various government agencies all of which add to the risk of developing a new nuclear generating unit. Recognizing the importance of nuclear power and its many environmental and economic benefits, the Company obtained a combined operating license ("COL") from the Nuclear

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

Regulatory Commission ("NRC") to support an additional unit at its existing North Anna Power Station. But based on the uncertainties of future carbon regulation, the Company has determined it is prudent to pause material development activities for North Anna 3. Going forward, the Company will continue to maintain the COL, which provides a valuable option in the future for a base load carbon-free generation resource that requires minimal land use. This resource was considered for further analysis in the Company's busbar curve.

Pumped Storage Hydroelectric Power
The Company is the operator and a 60% owner of the Bath County Pumped Storage Station, which is one of the world's largest pumped storage generation stations with a net generating capacity of 3,003 MW. Due to their size, pumped storage facilities are best suited for centralized utility-scale applications. For recent advancements on pumped storage hydroelectric power, see Section 5.4 of this 2018 Plan. This resource was not considered for further analysis in the Company's busbar curve.

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). This resource was not considered for further analysis in the Company's busbar curve.

Small Modular Reactors
Small modular reactors ("SMRs") are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured almost entirely off-site in factories and delivered and installed on site in modules. The small power output of SMRs equates to higher electricity costs than a larger reactor, but the initial costs of building the reactor are significantly reduced. An SMR 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. SMRs have more efficient containment and lessened proliferation concerns than standard nuclear units. SMRs are still in the early stages of development and permitting. The Company will continue to monitor the industry's ongoing research and development regarding this technology. This resource was not considered for further analysis in the Company's busbar curve.

5.1.3 NON-DISPATCHABLE RESOURCES

Onshore Wind
Wind resources are one of the fastest growing resources in the United States. The Company has considered onshore wind resources as a means of meeting the RPS goals, REPS requirements, and proposed CO_2 mitigation regulations, and also as a cost-effective stand-alone resource. The suitability of this resource is highly dependent on locating an operating site that can achieve an acceptable capacity factor. Additionally, these facilities tend to operate at times that are non-coincidental with peak system conditions and therefore generally achieve a capacity contribution significantly lower than their nameplate ratings. There is limited land available in the Company's service territory to develop onshore wind resources because wind resources in the eastern portions of the United States are available in specialized locations, such as on mountain ridges. Figure

5.1.3.1 displays the onshore wind potential of Virginia and North Carolina. The Company continues to examine onshore wind and has identified three feasible sites for consideration as onshore wind facilities in the western part of Virginia on mountaintop locations. This resource was considered for further analysis in the Company's busbar curve.

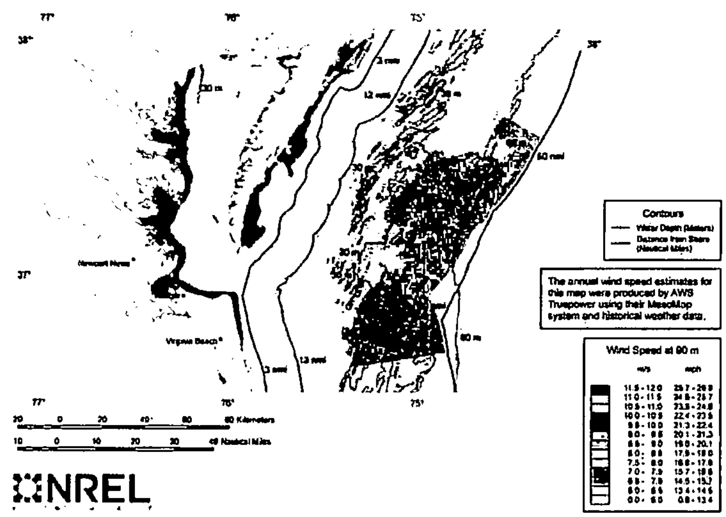
Figure 5.1.3.1 - Onshore Wind Resources

Source: National Renewable Energy Laboratory on April 2, 2018.

Offshore Wind

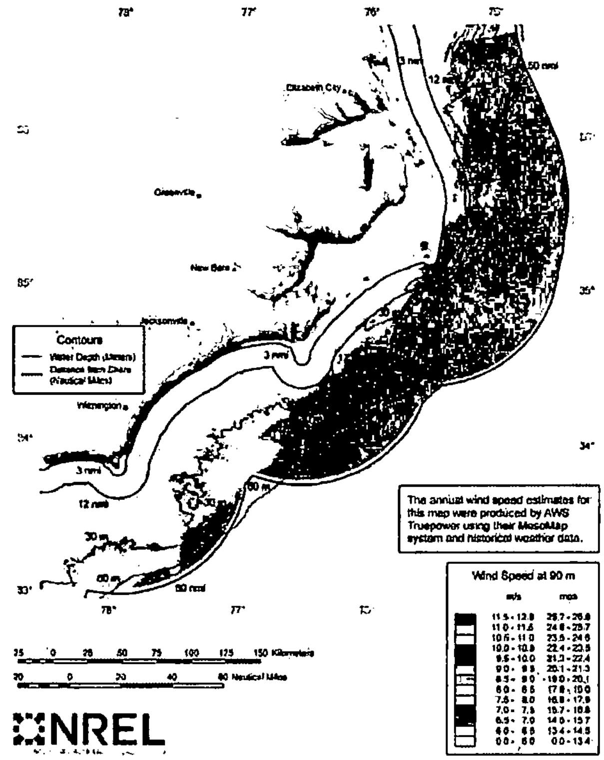
Offshore wind has the potential to provide a large, scalable renewable resource for Virginia. Figures 5.1.3.2 and 5.1.3.3 display the offshore wind potential of Virginia and North Carolina, respectively. Virginia has a unique offshore wind opportunity due to its shallow continental shelf extending approximately 40 miles off the coast, its proximity to load centers, the availability of local supply chain infrastructure, and world class port facilities. However, one challenge facing offshore wind development is its complex and costly installation and maintenance when compared to onshore wind. This resource was considered for further analysis in the Company's busbar curve.

Figure 5.1.3.2 - Offshore Wind Resources - Virginia



Source: Retrieved from U.S. Department of Energy on April 2, 2018

Figure 5.1.3.3 - Offshore Wind Resources - North Carolina

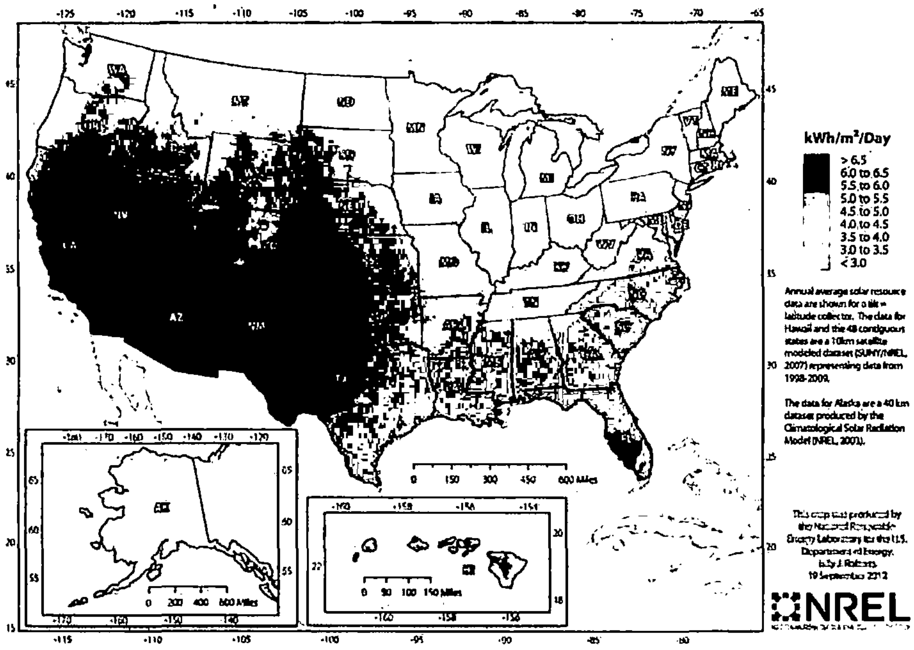


Source: Retrieved from U.S. Department of Energy on April 2, 2018.

Solar PV & Concentrating Solar Power

Solar PV and concentrating solar power ("CSP") are the two main types of solar technology used in electric power generation. Solar PV systems consist of interconnected PV cells that use semiconductor devices to convert sunlight into electricity. Solar PV technology is found in both large-scale and distributed systems and can be implemented where unobstructed access to sunlight is available. CSP systems utilize mirrors to reflect and concentrate sunlight onto receivers to convert solar energy into thermal energy that in turn produces electricity. CSP systems are generally used in large-scale solar plants and are mostly found in the southwestern area of the United States where solar resource potential is the highest. Solar PV technology was considered for further analysis in the Company's busbar curve, while CSP was not. Figure 5.1.3.4 shows the solar PV resources for the United States.

Figure 5.1.3.4 - Solar PV Resources of the United States



Source: National Renewable Energy Laboratory on April 2, 2018.

Solar generation is intermittent by nature, which fluctuates from hour-to-hour and in some cases from minute-to-minute. This type of generation volatility on a large scale could create distribution and transmission system instability. For example, Figure 5.1.3.5 shows how the solar eclipse affected the solar output at the Company's solar sites and Figure 5.1.3.6 shows the effect on aggregated solar generation and system load during the August 21, 2017 solar eclipse. Such an event demonstrates the need to observe these variable PV generation sites for reliable grid operation.

For these reasons, integration of solar PV at scale will require extensions and upgrades of the Company's supervisory control and data acquisitions system both at the transmission and distribution level. Additionally, in order to manage the added variability and uncertainty introduced by solar PV, other technologies may be needed, such as battery technology, quick start generation, voltage control technology, or pumped storage. The planning techniques and models currently used by the Company do not adequately assess the operational risk and cost that this type of generation could create, as further explained in Section 5.1.3.1.

Figure 5.1.3.5 – Solar Eclipse Effect on Solar Resources

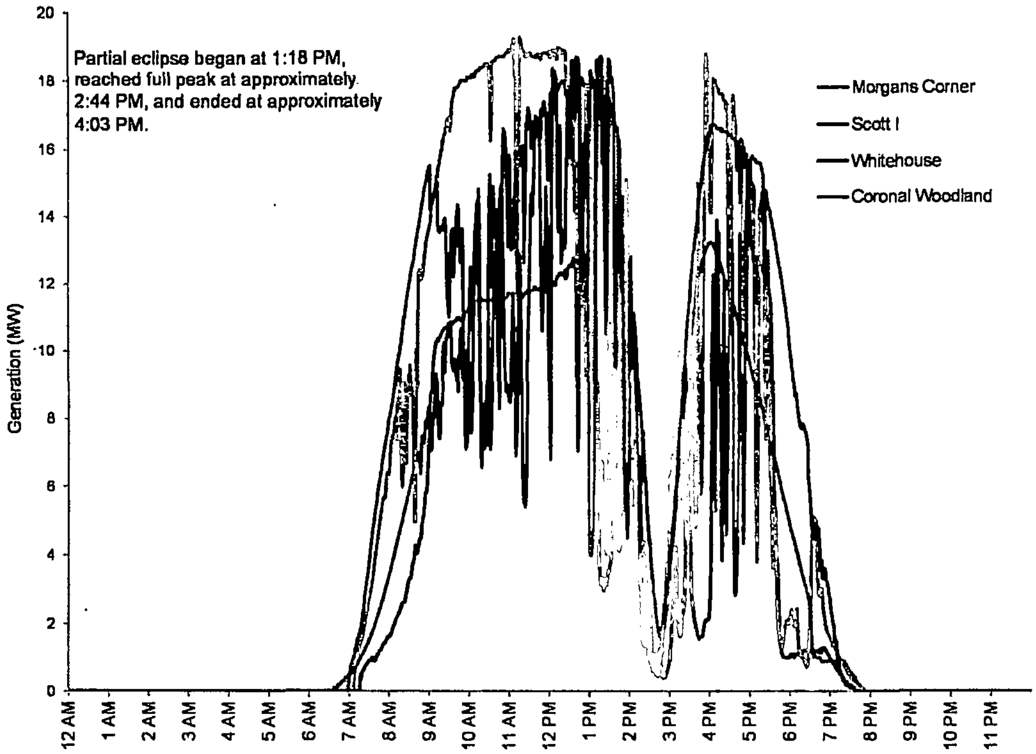
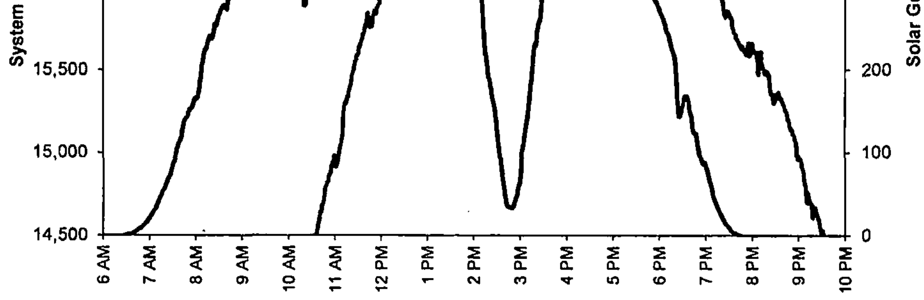


Figure 5.1.3.6 – Solar Eclipse Effect on System Load and Solar Generation



Note: The solar generation in this graph is an estimate based on the measured data available.

5.1.3.1 SOLAR PV INTEGRATION COST

The electric system reliability issues associated with the integration of large volumes of solar PV has been well documented in prior Plans. In this 2018 Plan, the Company has further refined its methods to estimate the solar PV integration costs as described below. Nevertheless, more work is required in order to fully assess the necessary grid modifications and associated costs of integrating solar PV.

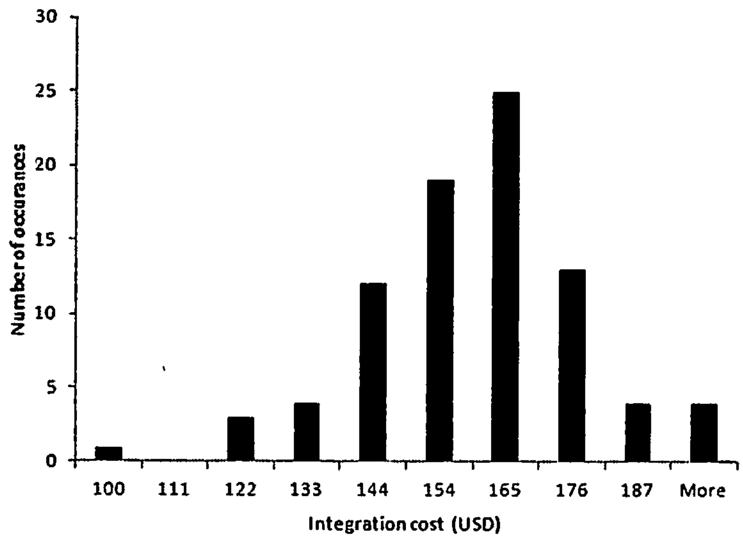
Transmission Cost

In order to assess transmission integration costs, the Company performed a steady state power flow analysis using a scenario where 7,000 MW of solar PV was interconnected to the Company's transmission grid. In the 2017 Plan, this analysis was conducted by utilizing the most optimal locations for siting solar PV generation in terms of cost. In this 2018 Plan, however, the 7,000 MW of solar PV were sited based on a random site selection process described below.

Like the analysis included in the 2017 Plan, the Company first identified a population of solar PV sites based on available land parcels in Virginia that were screened utilizing several criteria, including access to the Company's transmission grid and other land characteristics along with cost. This data was then combined with solar irradiance data provided by National Renewable Energy Laboratory ("NREL") in order to assess the solar generation potential of the specific sites. From this screening process, 326 solar PV sites were identified that represented approximately 37 GW (nameplate) of solar PV generation. Then 100 cases were created by randomly selecting feasible sites from the pre-screened set of 326 sites. Each selected case included approximately 7,000 MW (nameplate) of solar PV capacity.

Next, using the PSS®E power flow model, the 100 different solar cases were assessed under 2019 PJM summer peak demand conditions, while assuming maximum solar PV generation output (with reactive power support of +/- 0.95 power factor), and displacement of generation from other Company-owned facilities. The results of a majority of these modeling cases identified several low voltage and thermal violations that would require mitigation activities via physical enhancements to the Company's transmission system. The total integration costs were then evaluated by including the cost of these enhancements with other required system interconnection costs. The results of this stochastic analysis are reflected in the total integration cost (interconnection plus transmission improvements) frequency distribution shown in Figure 5.1.3.1.1. Based on this analysis, the expected value of the total integration cost is approximately $165.00/kW.

Figure 5.1.3.1.1 - Solar PV Integration Cost Histogram



The Company plans to build on this work in future Plans by considering dynamic system conditions arising out of sudden changes to solar PV output. Also, the Company intends to assess levels of solar PV that are higher and lower than the 7,000 MW in future Plans.

Distribution Cost
For purposes of this 2018 Plan, the Company utilized actual interconnection costs associated with solar PV facilities interconnected to the Company's distribution network. This integration cost was derived from the system impact studies performed using the Company's distribution network model under the relevant state jurisdictional generation interconnection process. The average actual interconnection cost of these solar PV facilities is approximately $133.00/kW.

Total Interconnection Cost
Going forward, it is not reasonable to assume that 100% of future solar PV additions to the Company's system will be interconnected solely at the transmission level or distribution level. For purposes of this 2018 Plan, the Company assumed that 70% of all future solar PV additions would be interconnected along the Company's transmission network, while 30% would be interconnected at the distribution level. These weighting factors were selected based on current solar PV facilities interconnected to the Company's network, along with solar PV facilities to be located in the Company's service territory that are listed in the PJM and state interconnection queues. A 70/30 weight results in an average interconnection cost of $155.00/kW.

As noted above, the interconnection cost for solar PV along the Company's transmission network ($165.00/kW) is based on 7,000 MW (nameplate) of solar PV generation. In the Company's judgment, however, it is unlikely that the same interconnection cost will be applicable for solar PV levels that are higher or lower than the 7,000 MW (nameplate) that was evaluated. Therefore, for purposes of this 2018 Plan, the Company used the interconnection cost schedule as listed in Figure 5.1.3.1.2 for modeling various nameplate levels of solar PV.

Figure 5.1.3.1.2 – Solar PV Interconnection Cost Schedule

From	Through	Interconnection Cost
0 MW	2,560 MW	$75/kW
2,561 MW	4,960 MW	$115/kW
4,961 MW	6,960 MW	$155/kW

Generation Costs
Re-dispatch generation costs are defined in this 2018 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. For example, 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 and more intermittent generation like solar PV or wind is added to the grid, additional uncertainty about re-dispatch costs is added due to 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 impact on generation operations at varying levels of solar PV penetration. To study the effects of these intermittent resources, hourly generation data from 26 individual sites was used to develop generation profiles from actual solar PV facilities currently interconnected to the Company's system. The study was performed at three different levels of solar penetration (up to 4,000 MW) to provide a range of results. The total system costs from each of these runs were compared to one another using several different mathematical average variances.

Relative to last year's study, several improvements were made to the process and data analyzed. First, the PLEXOS model was used for the production cost runs, which was able to incorporate an 8,760 hourly load profile for each of the solar sites studied. This is an improvement from the Strategist methodology used in the 2017 Plan, which incorporated a "typical day by month" load profile. Second, the dispatch from the PLEXOS model utilized the short-term ("ST") module, which was able to include dispatch constraints on thermal generating units such as ramp rates, minimum up and down times, and other constraints that were not considered in the previous year's modeling. The ST module better represents the strains put on a generating system by intermittent resources. Finally, the overall sample size used for the study has increased in both breadth and depth. Last year's generation study pulled from 9 sites that totaled approximately 76 MW. This year's study pulled from 26 sites that totaled approximately 220 MW. In this same regard, the geographic diversity in this year's study is greater, as several utility scale sites located in Virginia have a full year of operating data. There were also a greater number of horizontal tracker sites that have a full year of operational data for this year's study; last year's sample was made up of mostly smaller rooftop or fixed tilt projects.

The levelized cost differential between each of the cases resulted in an approximate re-dispatch cost of $1.78/MWh. This value was used as a variable cost adder for all solar PV generation evaluated in this 2018 Plan.

As noted above, this analysis incorporated the hourly modeling feature available in the PLEXOS model. The Company is using the feature along with similar features in its AURORA model in order to examine the issues created by intermittent generation in a more robust manner. The Company is currently using this hourly feature and sub-hourly features contained in PLEXOS and AURORA to better examine and value of electricity storage, and other fast ramping resources such as aero-derivative turbines. The Company intends to incorporate the results of these studies in future Plans.

Limitations of the Solar Integration Cost Analysis

While this 2018 Plan further refines solar PV integration costs as described above, it is important to note that such costs are limited to the scope of the analysis conducted. For example, the transmission integration costs described above are assessed under steady-state conditions. Under dynamic conditions, it is highly likely that the integration costs will also be different. The same likelihood applies at the distribution level. Furthermore, although the distribution integration costs described above are based on actual interconnection cost data, that data does not include distribution substation upgrade costs that may be necessary to support a high influx of solar PV integration at the distribution level. Nor does it include transmission upgrade cost to the extent solar PV generation at the distribution level back-feeds onto the transmission grid.

From a generation perspective, the costs described above are only intended to assess re-dispatch costs. The costs associated with additional spinning reserve to support variable output from solar PV and the additional cost of machine wear and tear resulting from increased cycling have not yet been evaluated by the Company. The Company continues to develop processes that will aid in the cost evaluation associated with solar PV integration. The results of these evaluations will be included in future Plans filed by the Company.

Another major assumption used by the Company in this 2018 Plan is that the majority (70%) of future solar PV facilities would be interconnected at the transmission level. The Company maintains that this assumption is reasonable given current available information, including the economies of scale associated with large solar PV facilities. But if solar PV costs continue to decline, and given customer and society's preference for clean reliable energy, it is not unreasonable to expect that a large percentage of new solar PV facilities will be installed at or near customer homes and businesses or at other locations along the Company's distribution network. Given this plausible future outcome, the Company's distribution grid will require significant modification in order to maintain reliable service to its customers. This is one of the driving forces behind the GTSA signed into Virginia law. A high-level summary of the Company's grid modernization plan is reflected in Section 5.1.4.

Finally, for purposes of this 2018 Plan, the Company has placed an annual 480 MW (nameplate) limitation with respect to the level of solar PV generation that can achieve commercial operation in any given year. The Company's ability to develop and bring online multiple solar PV facilities annually is limited due to the schedules associated with land access, permitting, equipment procurement, and regulatory approvals.

Distribution Feeder Hosting Capacity Analysis

As part of this 2018 Plan, the Company has developed a process to identify PV hosting capacity at the distribution feeder level.

Typically, circuits and substations near load centers such as Northern Virginia have the capacity to integrate high levels of distributed generation such as solar PV. However, land availability in these regions can be low. Therefore, the analysis was performed based on prospective land for solar PV project development within close proximity to the Company's distribution facilities. Prospective locations and sizes of solar PV sites were chosen by the land data provided by the Company's GIS system. The land data was provided at one meter resolution and land parcels characterized by pasture, hay, and cultivated crops were considered as possible solar sites.

The initial step was to identify distribution level feeders with three phase (greater than or equal to 12.5 kV), within a quarter mile of the land parcels sized 40 acres (based on 8 acres per MW) and greater. This resulted in 412 feeders in Virginia. Next, additional feeders were eliminated due to voltage rise greater than 3% with 5 MW connected at unity power factor. Circuits that already had significant solar resources behind the step-down transformers and line regulators were eliminated as well.

Each remaining feeder was then evaluated to determine the maximum amount of PV that could be connected based on the nearest parcels. Some other filtering criteria were that the voltage must not rise more than 3%, no equipment rating could be exceeded, and substation transformer only loaded to 70% of nameplate at no load scenario on the feeder. This resulted in 529 sites on 303 feeders, 221 substation transformers, and 160 substations. These identified feeders can support approximately 4,200 MW of solar based on the substation transformers' loading capacity. Virtually every circuit will need station regulators added or upgraded to keep voltage within acceptable ranges. Additional PV hosting capacity could be accommodated by re-conductoring, substation transformer upgrades, or operating PV inverters on a leading power factor. It should be acknowledged that this analysis did not consider the aggregate effect of the distributed solar PV on to the transmission grid. As new DG projects are interconnected to the Company's distribution system, or as the distribution system is modified, hosting capacity will change. This analysis was conducted to identify the overall capacity of the Company's current distribution system to address future solar PV development.

5.1.4 GRID MODERNIZATION

The Company recognizes that customer expectations are evolving and that service reliability improvements will be required to maintain reliability, address resilience, enhance physical and cyber security, and improve the overall customer experience. The grid must adapt in order to meet these expectations.

As stated earlier in this 2018 Plan, utility-scale solar continues to be cost competitive with other more traditional forms of generation. The anticipated proliferation of smaller-scale DERs includes renewable resources, such as solar and wind, and battery technology. As costs continue to decline, it is not unreasonable to expect that the Company or its customers will continue to install solar or other DERs at their homes, businesses, or other locations along the Company's distribution network.

Like most of the industry, the Company's electric distribution system was designed for "one-way" delivery of energy to meet peak demand—from the generator, to the transmission network, to the distribution network, and then to the customer meter.

To the extent that DER proliferation and the adoption of EVs and battery storage continues, the Company must be prepared to meet a new paradigm that will require the Company to transform its existing electric delivery from its original one-way design to a modern two-way network capable of facilitating instantaneous energy injections and withdrawals at any point along the network while continuing to maintain the highest level of reliability and while maintaining service levels that customers expect and deserve. The first step in this transformation process is a modernization of the distribution grid.

To that end, the Company has begun the initial planning associated with a transformational grid modernization effort. The modernized system would need to include elements such as (i) "smart" or AMI meters; (ii) improved communications network; (iii) intelligent devices to monitor, predict and control the grid; (iv) distribution substation automation; (v) replace aging infrastructure; (vi) improvements to security; vii) methods to investigate new innovative technologies; and (viii) an enhanced customer information platform to enable management of customers' energy usage.

Currently, at the generation and transmission level, the Company's electric system operators possess real-time visibility, communications, and control. Implementing a sophisticated system of communication and control similar to what system operators currently utilize at the generation and transmission levels will not only improve and modernize the distribution grid, but will make it adaptable to evolving technological changes.

In a future where potentially tens of thousands of DER devices are located at homes or businesses throughout Virginia, system operators will need the ability to monitor these devices in order to operate the distribution network so that overall electric service reliability can be safely and efficiently maintained. In addition to ensuring reliability and accommodating integration of distributed generation into the grid, this modernization program will offer customers a new information platform and opportunities to manage their energy usage. The Company continues to assess the details and costs associated with developing a future distribution grid that is stronger, smarter, and greener than today's network. The Company intends to report those findings in future Plans.

5.1.5 THIRD-PARTY MARKET ALTERNATIVES TO CAPACITY RESOURCES

Solar

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 July 2015, the Company issued an RFP for new utility-scale solar PV generating facilities located in Virginia. As a result of this RFP, the Company contracted with two developers for approximately 40 MW (nameplate) of solar. Since then, the developer of one of the 20 MW solar facilities failed to obtain a permit and terminated the PPA; the other PPA came online in December 2017. During this same timeframe, the Company brought online three self-build solar facilities (Scott, Whitehouse, and Woodland) totaling approximately 56 MW (nameplate).

In 2017, the Company issued three solicitations that included requests for solar generation. The first solicitation was a request for information ("RFI") for renewable resources to potentially serve customers interested in being served by 100% renewable resources on a continuous hourly basis. The second solicitation was an RFP for the Company's Community Solar Pilot Program seeking small solar resources (2 MW or less) totaling 10 MW. The third solicitation was an RFP for approximately 300 MW of solar and onshore wind generation located in Virginia. The Company received a number of solar proposals through the RFI, but has yet to contract with any of those resources pending a decision from the SCC on the Company's application for 100% renewable energy tariffs in Case Nos. PUR-2017-00060 and PUR-2017-00157. Both RFPs attracted considerable interest from solar developers. The Company continues to evaluate responses to the RFP for the Community Solar Pilot Program and expects to contract with resources from that solicitation in 2018, pending approval of the Company's Community Solar application before the SCC in Case No. PUR-2018-00009. Finally, the Company continues to evaluate responses to the RFP for approximately 300 MW of solar and onshore wind generation and expects to make a decision on those proposals in 2018.

In North Carolina, over the same period, the Company has signed 83 PPAs totaling approximately 570 MW (nameplate) of new solar NUGs. Of these, 479 MW (nameplate) are from 67 solar projects that were in operation as of March 2018. The majority of these developers 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 ("PURPA"), as approved in Docket No. E-100, Sub 136 (2012), Docket No. E-100, Sub 140 (2014), and Docket No. E-100, Sub 148 (2016). Going forward, the Company's qualifying facility PPAs will reflect the amended provisions of NCGS § 62-156, as enacted by North Carolina House Bill 589, governing payments for avoided capacity and for PURPA contract availability and terms.

Wind

The Company received several proposals for wind generation resources in PJM through the RFI mentioned above. The Company has yet to contract with any of these resources pending a decision on its tariff application. The Company received one wind proposal through its RFP for approximately 300 MW of solar and onshore wind generation. The proposal's price was not competitive when compared with other solar alternatives.

Other Third-Party Alternatives

Over the past two years, the Company has evaluated a number of opportunities to extend the terms of the current NUG contracts that have recently expired or will expire in the next several years. Many of these were evaluated through a formal RFP process, while others were evaluated through direct contact with the existing NUG owner. However, none of these existing NUGs were found to be cost-effective options for customers when compared to other options. Additionally, the Company has been in early discussions with a number of developers of other new third-party generation alternatives over the past year. However, none of these discussions have matured to the point of the Company receiving or being able to evaluate a firm PPA price offer.

In 2017, one of the Company's NUGs, Roanoke Valley Facility I and II, ceased operations, but the amended agreement called for replacement power equal to the previously contracted amounts to be provided to the Company through the term of the original NUG contract, ending in March 2019. While the Roanoke Valley Facility is no longer listed as a NUG in Appendix 3B, the Company's future resource planning includes the replacement power through the term of this agreement.

5.2 LEVELIZED BUSBAR COSTS

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

Figures 5.2.1 and 5.2.2 display summary results of the busbar model comparing the economics of the different technologies discussed in Sections 5.1.2 and 5.1.3. The results were 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 5.2.1 - Dispatchable Levelized Busbar Costs (2023 COD)

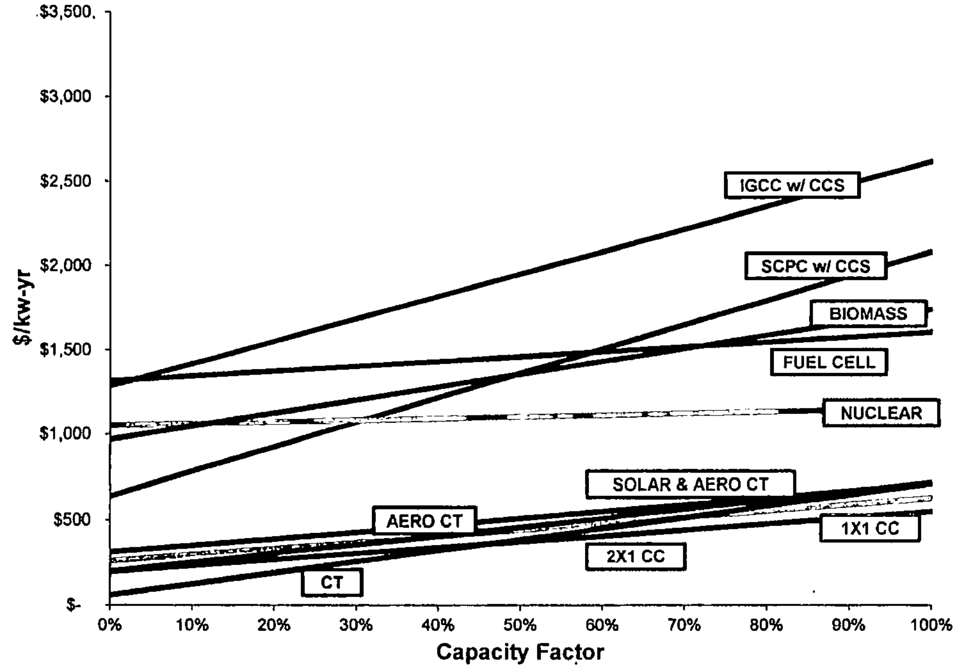
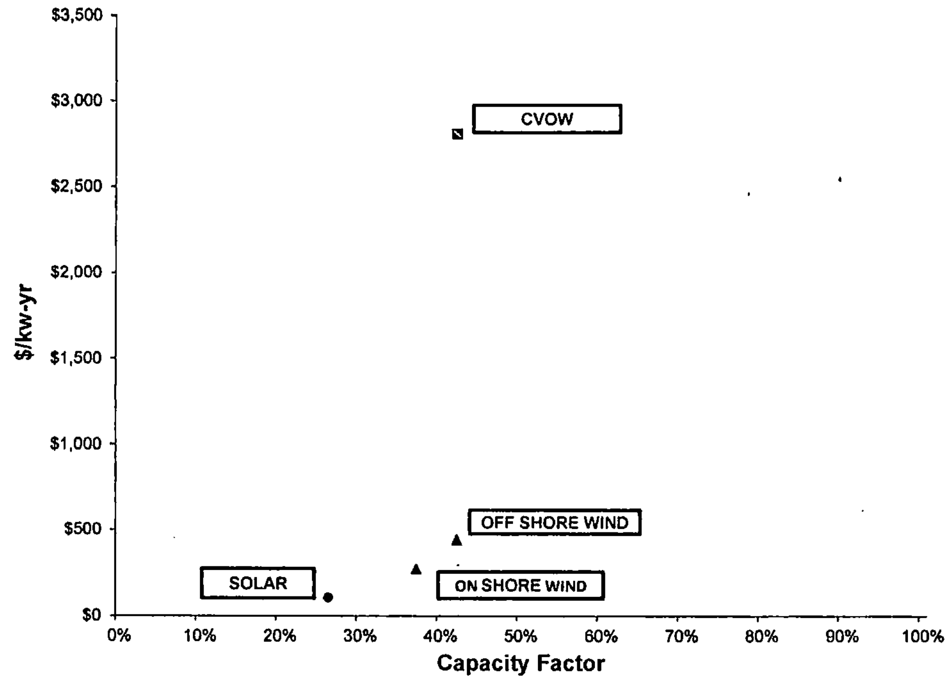


Figure 5.2.2 - Non-Dispatchable Levelized Busbar Costs (2023 COD)



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Appendix 5A contains the tabular results of the screening level analysis. Appendix 5B displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated 2018 real dollar construction costs.

In Figure 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 busbar costs above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher cost generation, however, may be necessary to achieve other constraints like those required by potential carbon regulation. Figures 5.2.1 and 5.2.2 allow comparative evaluation of resource types. The 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.

As shown in Figure 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 2x1 technology is the most economical option for capacity factors greater than approximately 25%. Also, as depicted in Figure 5.2.2, solar PV is a competitive choice at capacity factors of approximately 25%.

Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods, therefore more capacity would be required to maintain the same level of system reliability. For example, onshore wind provides only 13% of its nameplate capacity as firm capacity that is available to meet the Company's PJM resource requirements as described in Chapter 4. Figure 5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability. The Company is routinely updating and evaluating the costs and availability of renewable resources.

Figure 5.2.3 identifies some basic capacity and energy differences between dispatchable resources and non-dispatchable resources. One additional factor to consider for solar installation is the amount of land required. For example, the installation of 1,000 MW of solar requires approximately 8,000 acres of land, which would encompass 12.5 square miles.

Figure 5.2.3 - Comparison of Resources by Capacity and Annual Energy

Resource Type	Nameplate Capacity (MW)	Estimated Firm Capacity (MW)	Estimated Capacity Factor (%)	Estimated Annual Energy (MWh)
Onshore Wind	1,000	130	37%	3,241,200
Offshore Wind	1,000	167	42%	3,635,400
Solar PV	1,000	229	26%	2,277,600
Nuclear	1,000	1,000	92%	8,059,200
CC	1,000	1,000	80%	7,008,000
CT	1,000	1,000	20%	1,752,000

Note: 1) Solar PV firm capacity has 22.86% value through 35 years of operation.

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. 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.

5.3 GENERATION UNDER DEVELOPMENT

Extension of Nuclear Licensing

An application for a subsequent or second license renewal is allowed during a nuclear plant's first period of extended operation — i.e., in the 40 to 60 years range of its service life. Surry Units 1 and 2 entered into that period in 2012 (Unit 1) and 2013 (Unit 2). North Anna Units 1 and 2 will enter into that period in 2018 (Unit 1) and 2020 (Unit 2).

The Company informed the NRC in a letter dated November 5, 2015, of its intent to submit a subsequent license renewal application for Surry Power Station Units 1 and 2. Under the current schedule, the Company intends to submit an application for the second renewed Operating Licenses in accordance with 10 CFR Part 54 by the end of the first quarter of 2019. The issuance of the renewed license would follow successful NRC safety and environmental reviews tentatively in the 2022 timeframe.

The Company informed the NRC in a letter dated November 9, 2017, of its intent to submit a subsequent license renewal application for North Anna Power Station Units 1 and 2. Under the current schedule, the Company intends to submit an application for the second renewed Operating Licenses in accordance with 10 CFR Part 54 by the end of the 2020. The issuance of the renewed license would follow successful NRC safety and environmental reviews tentatively in the 2023 timeframe.

There has been no additional correspondence between the Company and the NRC concerning any second license renewals since November 2017. The Company has, however, participated in public industry meetings during the last 12 months with other potential utility applicants in which second license renewal applications have been discussed with the NRC.

NRC draft guidance on the requirements for a second license renewal was issued for public comment in December 2015. The industry, including the Company and interested stakeholders, has reviewed the guidance information to understand the pre-decisional technical requirements and additional aging management program requirements. The nuclear industry, including the Company, provided comments through the Nuclear Energy Institute in February 2016, which was the end of the public comment period. The NRC is currently evaluating the industry and stakeholder comments. Following the issuance of the final NRC guidance documents, the Company will begin finalizing the technical evaluation and additional aging management program requirements required to support the second license renewal application.

The preliminary cost estimates for the extension of the nuclear licenses for Surry Units 1 and 2, as well as North Anna Units 1 and 2 can be found in Appendix 5F.

Solar

US-3 Solar 1, 142 MW (nameplate), and US-3 Solar 2, 98 MW (nameplate), are Company-owned Virginia utility-scale solar generation currently under development. These two projects are included in the 2018 Plan.

Offshore Wind

The Company continues to pursue offshore wind development in a prudent manner for its customers and for the state's economic development. Offshore wind has the potential to provide a scalable renewable resource if it can be achieved at reasonable cost to customers. To help determine how this can be accomplished, the Company is involved in two active projects: (i) CVOW and (ii) commercial development in the Virginia Wind Energy Area ("WEA"), both of which are located approximately 27 miles (approximately 24 nautical miles) off the coast of Virginia. A complete discussion of these efforts is included in Section 5.4.

Figure 5.3.1 and Appendix 5C provide the projected in-service dates and capacities for generation resources under development for the Alternative Plans.

Figure 5.3.1 - Generation under Development[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Capacity (Net MW)	
						Summer	Winter
2020	US-3 Solar 1	VA	Solar	Intermittent	142	33	33
2021	CVOW	VA	Wind	Intermittent	12	2	2
2021	US-3 Solar 2	VA	Solar	Intermittent	98	22	22
2032	Surry Unit 1 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
2033	Surry Unit 2 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
2038	North Anna Unit 1 Nuclear Extension	VA	Nuclear	Baseload	838	838	868
2040	North Anna Unit 2 Nuclear Extension	VA	Nuclear	Baseload	834	834	863

Notes: 1) All Generation under development projects and capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approval.

5.4 EMERGING AND RENEWABLE ENERGY TECHNOLOGY DEVELOPMENT

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

Research and Development Initiatives – Virginia

Pursuant to Va. Code § 56-585.2, utilities that are participating in Virginia's RPS program are allowed to meet up to 20% of their annual RPS goals using RECs issued by the SCC for investments in renewable and alternative energy research and development activities. In addition to three projects completed in 2014, the Company is currently partnering with nine institutions of higher education on Virginia renewable energy research and development projects. The Company filed its annual report in November 2017, analyzing the prior year's PJM REC prices and quantifying its qualified investments to facilitate the SCC's validation and issuance of RECs for Virginia renewable and alternative energy research and development projects.

Research and Development Initiatives – North Carolina

Pursuant to NCGS § 62-133.8(h), the Company completed construction of its microgrid demonstration project at its North Carolina Kitty Hawk District Office in July 2014. The microgrid project included innovative distributed renewable generation and energy storage technologies. A microgrid, as defined by the DOE, is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid, allowing it to operate in grid-connected or island mode. The project included four different types of micro-wind turbines, a solar PV array, and a lithium-ion battery integrated behind-the-meter with the existing on-site diesel generator and utility feed. In the third quarter of 2015, the Company integrated two small, residential-sized fuel cells in order to study the fuel cell's interaction with the on-site renewable energy technologies in a microgrid environment. The knowledge gained from this microgrid project has been used to further assess the best practice for integrating large amounts of intermittent generation (such as wind and solar PV) into the existing grid.

Offshore Wind – Virginia

The Company is actively participating in offshore wind policy and innovative technology development in order to identify ways to advance offshore wind generation responsibly and cost-effectively. The Virginia General Assembly passed legislation in 2010 to create the Virginia Offshore Wind Development Authority ("VOWDA") to help facilitate offshore wind energy development in the Commonwealth. The Company continues to actively participate in VOWDA, as well as the Virginia Offshore Wind Coalition ("VOW"). The VOW is an organization comprised of developers, manufacturers, utilities, municipalities, businesses, and other parties interested in offshore wind. This group advocates on the behalf of offshore wind development before the Virginia General Assembly and with the Virginia delegation to the U.S. Congress.

As part of its ongoing commitment to bring cleaner energy to its customers, the Company is moving forward on the Mid-Atlantic's first offshore wind project in a federal lease area. In July 2017, the Company announced that it had signed an agreement and strategic partnership with Ørsted Energy of Denmark, a global leader in offshore wind development, to build two 6 MW turbines off the coast of Virginia Beach. The Company remains the sole owner of the project.

In January 2018, an engineering, procurement, and construction ("EPC") agreement was executed with Ørsted and development work on CVOW is ongoing to support a targeted installation by the end of 2020, with capacity being available in the 2021 RPM auction. The project is an important first step toward offshore wind development for Virginia and the United States. Along with clean energy, it will provide the Company valuable experience in permitting, constructing, and operating offshore wind resources which will help inform potential commercial scale development of the adjacent 112,000 acre wind lease area.

Energy Storage Technologies

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

There is also increasing interest in pumped storage hydroelectric power as a storage mechanism for the intermittent and highly variable output of renewable energy sources such as solar and wind. For example, the 2017 Regular Session of the Virginia General Assembly passed Senate Bill 1418 ("SB 1418") supporting 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 and such facilities and associated resources are located in the coalfield region of the Commonwealth." The General Assembly adopted the Governor's amendments to SB 1418 on April 5, 2017. The bill became law effective July 1, 2017.

Following the approval of SB 1418, the Company is in the early stages of conducting feasibility studies for a potential pumped storage facility in the western part of the Commonwealth of Virginia. The Company acknowledges that pumped storage is a proven dispatchable technology that would complement the ongoing integration of renewable solar and wind resources.

In addition to pumped storage hydroelectric power, the Company continues to monitor advancements in other energy storage technologies, such as batteries and flywheels. These energy storage technologies can also be used to provide grid stability as more renewable generation sources are integrated into the grid. In addition to reducing the intermittency of wind and solar generation resources, batteries can shift power output from periods of low demand to periods of peak demand. This increases the dispatchability and flexibility of these resources.

Electric Vehicle Initiatives

Various automotive original equipment manufacturers ("OEMs") have released EVs for sale to the public in the Company's service territory. The Company continues to monitor the introduction of EV models from several other OEMs in its Virginia service territory. While the overall penetration of EVs has been somewhat lower than anticipated, recent registration data from the Virginia Department of Motor Vehicles ("DMV") and IHS, Inc. ("IHS", formerly Polk Automotive), demonstrates steady growth. The Company did not augment its load forecast used in this 2018 Plan to account for additional load from EVs. Therefore, only incremental load from EVs that is imbedded in history is partially included in the load forecast used in the 2018 Plan.

5.5 FUTURE DSM INITIATIVES

In 2016, the Company conducted a residential appliance saturation survey with results shown in Figure 5.5.1. All else equal, the reduction in average energy use per household would be expected to reduce the technical, economic, and achievable potential savings. Lower consumption means that there is less opportunity for energy savings. However, the "all else equal" caveat is an important one because factors that change the economics of individual DSM measures also affect potential, and possibly offset the impacts of consumption trends. Such factors include changes to avoided costs (which can change the cost effectiveness of a measure from a societal standpoint), rates (which can change the cost effectiveness of a measure from the customer standpoint), and measure costs (which can affect both). The introduction of new technologies can also increase potential in the long run. On the other hand, codes and standards tend to reduce the achievable potential available to programs by improving the efficiency of baseline equipment or homes. In these situations, society captures the savings, but through a separate avenue from efficiency programs.

Figure 5.5.1 – Residential Energy Intensities (average kWh over all households)

	Virginia (2013)			Virginia (2016)			Percent Change
kWh/household	Single Family	Multi-family	All Homes	Single Family	Multi-family	All Homes	All Homes
Base Split-System Air Conditioner	1,557	621	1,398	1,348	666	1,230	-12%
Base Early Replacement Split-System Air Conditioner	325	130	292	470	122	411	41%
Base Heat Pump Cooling	1,321	667	1,211	997	687	944	-22%
Base Early Replacement Heat Pump Cooling	201	120	187	203	49	177	-5%
Base Room Air Conditioner	91	35	81	54	55	54	-33%
Base Early Replacement Room Air Conditioner	17	3	15	4	0	3	-80%
Base Dehumidifier	17	8	15	287	38	245	1533%
Base Furnace Fans	1,058	458	956	1,085	442	976	2%
Base Heat Pump Space Heating	1,344	581	1,215	1,527	610	1,372	13%
Base Early Replacement Heat Pump Heating	339	139	305	358	118	317	4%
Base Resistance Space Heating	656	600	647	376	348	372	-43%
Base High-Efficiency Incandescent Lighting, 0.5 hrs/day	151	67	137	93	46	85	-35%
Base High-Efficiency Incandescent Lighting, 2.5 hrs/day	590	279	537	332	164	304	-41%
Base High-Efficiency Incandescent Lighting, 6 hrs/day	399	174	361	190	115	177	-46%
Base Lighting 15 Watt CFL, 0.5 hrs/day	20	9	18	17	10	16	-11%
Base Lighting 15 Watt CFL, 2.5 hrs/day	82	37	74	70	40	65	-12%
Base Lighting 15 Watt CFL, 6 hrs/day	54	25	49	48	27	43	-12%
Base Lighting 9 Watt LED, 0.5 hrs/day	1	1	1	3	3	3	200%
Base Lighting 9 Watt LED, 2.5 hrs/day	10	6	10	24	17	23	130%
Base Lighting 9 Watt LED, 6 hrs/day	10	5	9	23	8	20	122%
Base Specialty Incandescent Lighting, 0.5 hrs/day	64	21	57	79	24	69	21%
Base Specialty Incandescent Lighting, 2.5 hrs/day	266	85	236	323	98	285	21%
Base Specialty Incandescent Lighting, 6 hrs/day	176	58	156	213	67	189	21%
Base Fluorescent Fixture 1.8 hrs/day	442	135	390	442	121	388	-1%
Base Refrigerator	583	395	535	582	438	557	4%
Base Early Replacement Refrigerator	80	54	75	200	126	187	149%
Base Second Refrigerator	352	6	293	405	23	340	16%
Base Freezer	334	52	286	150	63	136	-52%
Base Early Replacement Freezer	59	9	51	110	21	95	86%
Base Second Freezer	18	0	15	14	0	11	-27%
Base 40 gal. Water Heating	1,569	1,441	1,547	920	261	808	-48%
Base Early Replacement Water Heating	277	254	273	1,071	1,176	1,089	299%
Base Clothes washer	43	25	40	44	35	43	8%
Base Clothes Dryer	600	469	578	691	570	670	16%
Base Dishwasher	202	152	194	221	180	214	10%
Base Pool Pump	158	0	131	45	0	37	-72%
Base Plasma TV	77	34	70	35	24	33	-53%
Base LCD TV	180	103	167	185	104	171	2%
Base CRT TV	59	31	54	9	6	8	-85%
Base Set-Top Box	221	102	201	221	144	208	3%
Base DVD Player	26	17	25	31	17	29	16%
Base Desktop PC	241	128	222	274	107	245	10%
Base Laptop PC	43	26	40	53	37	51	28%
Base Cooking	528	451	515	659	617	652	27%
Base Miscellaneous	600	500	583	600	500	583	0%
Whole House	15,420	8,516	14,252	15,083	8,330	13,940	-2%

The Company conducted a DSM market potential study in 2017 ("2017 DSM Potential Study"), with results illustrated in Figure 5.5.2. The 2017 DSM Potential Study identified the technical, economic, and achievable market potential of energy savings for all measures in the Company's residential and commercial sectors. The technical market potential reflects the upper limit of energy savings assuming anything that could be achieved is realized. Similarly, the economic potential reflects the upper limit of energy savings potential from all cost-effective measures. The achievable potential reflects a more realistic assessment of energy savings by considering what measures can be cost-effectively implemented through a future program. The result is a list of cost-effective measures that can ultimately be evaluated for use in future program designs and a high level estimate of the amount of energy and capacity savings still available in the Company's service territory. The achievable potential identified in the 2017 DSM Potential Study is shown in Figure 5.5.2.

Figure 5.5.2 – 2018 Plan vs. DSM System Achievable Market Potential

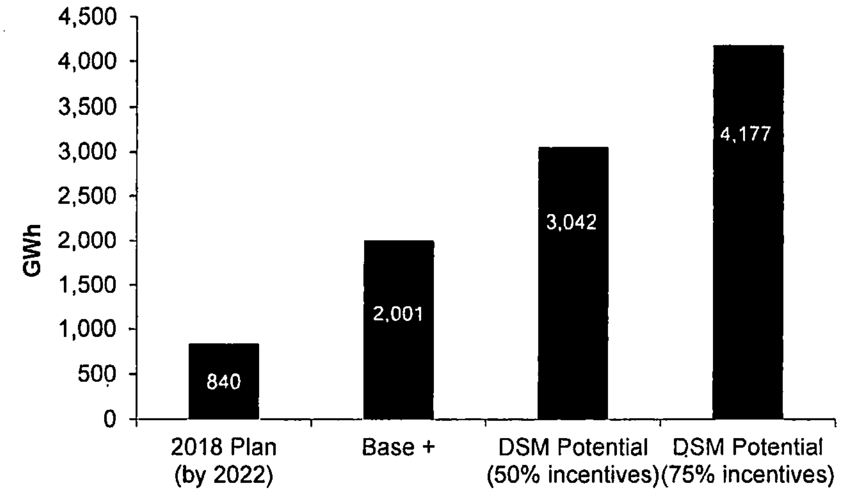
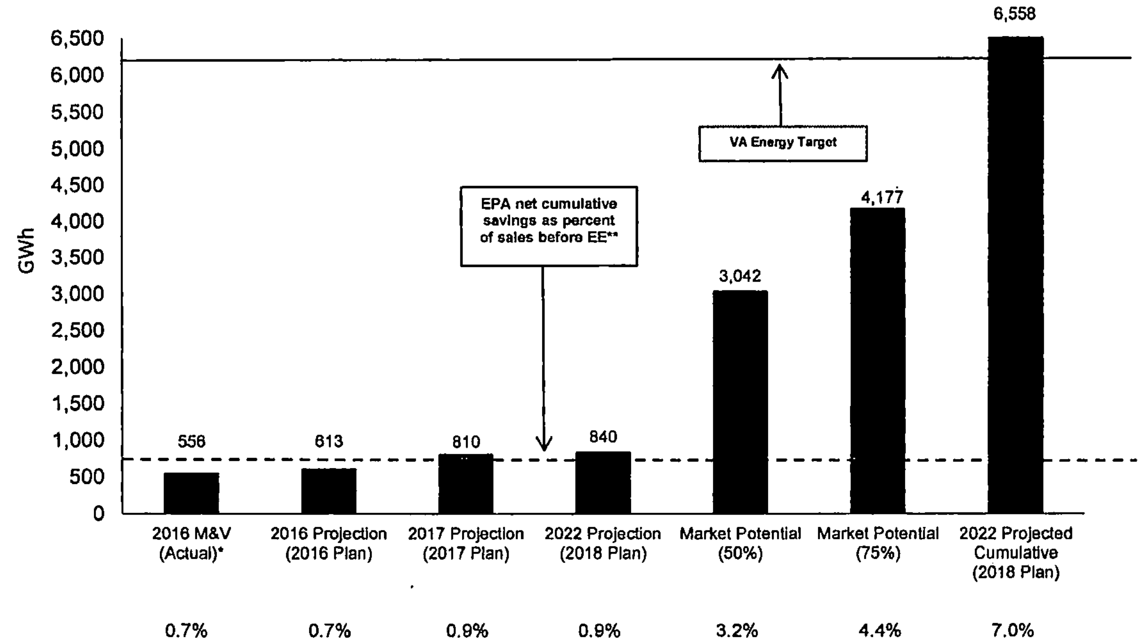


Figure 5.5.3 shows a comparison of the actual energy reductions for 2016 compared to the projected energy reductions for 2016. The actual energy reductions were 91% of the projected energy reductions for 2016. The energy reductions projected for 2022 in the 2017 Plan were 1,217 GWh. This level of energy reduction represents 40% of the amount shown in the 2017 DSM Potential Study (50% incentive level) for 2022.

Figure 5.5.3 – DSM Projections/Percent Sales



Note: *Actual energy savings are a function of SCC-approved program funding levels and measured energy savings/participation relative to program design projections.
**EPA Demand-Side Energy Efficiency Technical Support Document August 2015.
https://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents
"Data File: Demand-Side Energy Efficiency Appendix – Illustrative 7% Scenario.xlsx". Net Cumulative savings of 0.66% as percent of sales before EE.

A reasonable approach is to examine the projected energy reductions as a percent of energy sales. Those values are shown at the bottom of the graph for each of the energy reduction bars. Currently, the Company is producing actual energy reductions at a rate of about 0.7% of system energy sales. That is compared to a projected energy reduction of about 0.9% of sales in 2017. The projected energy reduction for the year 2022 is around 0.9% of sales. This level of energy reductions from DSM programs falls within a range of reasonable energy reductions. A reasonable range of energy reductions currently lies in a band of 0.5% to 1.0% of sales on an incremental basis.

In October 2017, the Company issued an RFI to solicit program concepts for a broad range of DSM programs. The information received in the RFI was used to develop an RFP for specific programs, which included a request for detailed design information. The RFP requested proposals for programs that may include measures identified in the 2017 DSM Potential Study, as well as other potential cost-effective measures based upon the current market trend. Responses from the RFP will be used to evaluate the feasibility and cost-effectiveness of proposed programs for customers in the Company's service territory.

In this 2018 Plan, there is a total reduction of 805 GWh by the end of the Planning Period in DSM related savings. By 2022, there are 840 GWh of reductions included in this 2018 Plan. There are several drivers that will affect the Company's ability to meet the current level of projected GWh reductions, including the cost-effectiveness of the DSM programs when filed, the SCC approval of newly filed programs, continuation of existing programs, the final outcome of proposed environmental regulations, and customers' willingness to participate in approved DSM programs.

5.5.1 STANDARD DSM TESTS

To evaluate DSM programs, the Company utilized four of the five standard tests from the California Standards Practice Manual. Based on SCC and NCUC findings and rulings in the Company's Virginia DSM proceedings[28] and North Carolina DSM proceedings,[29] the Company's future DSM programs are evaluated on both an individual and portfolio basis.

From the 2013 Plan going forward, the Company made changes to its DSM screening criteria in recognition of amendments to Va. Code § 56-576 enacted by the Virginia General Assembly in 2012 that a program "shall not be rejected based solely on the results of a single test." Therefore, the Company considers including DSM programs that have passing scores (cost/benefit scores above 1.0) on the Participant, Utility Cost, and Total Resource Cost ("TRC") tests.

In addition, during the 2017 planning cycle, the Company made a change in its DSM screening criteria based on the guidance in the Final Order in the 2016 DSM Proceeding where it denied the Phase VI Residential Home Energy Assessment Program. In this Order, the SCC states:

> [A]ccording to the Company's [Ratepayer Impact Measure ("RIM")] score of 0.39 for this program, the costs to non-participants far exceed the system-wide benefits. Furthermore, at a ratio of 1.22, the TRC Test for the Residential Home Energy Assessment Program, which measures the impact to the utility and program participants, does not significantly offset the low RIM score. Moreover, a comparison of the [NPV] of the tests does not alter our conclusion.[30]

The Company's analysis and evaluation during the 2018 Plan and 2017 DSM planning cycles were guided by this order.

Although the Company uses these criteria to assess DSM programs, there are circumstances that require the Company to deviate from the aforementioned criteria and evaluate certain programs that do not meet these criteria on an individual basis. These DSM programs serve important policy and public interest goals, such as those recognized in approving the Company's Low Income Program[31] and, more recently, the Company's Income & Age Qualifying Home Improvement Program.[32]

5.5.2 REJECTED DSM PROGRAMS

The Company did not reject any programs as part of the 2018 IRP process. A list of DSM rejected programs from prior IRP cycles is shown in Figure 5.5.2.1. Rejected programs may be re-evaluated and included in future DSM portfolios.

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[28] Case Nos. PUE-2009-00023, PUE-2009-00081, PUE-2010-00084, PUE-2011-00093, PUE-2012-00100, PUE-2013-00072, PUE-2014-00071, PUE-2015-00089, and PUE-2016-00111.

[29] Docket No. E-22, Subs 463, 465, 466, 467, 468, 469, 495, 496, 497, 498, 499, 500, 507, 508, 509, 523, 524, 536, 538, and 539.

[30] *Petition of Virginia Electric and Power Company, For approval to implement new, and to extend existing, demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUE-2016-00111, Final Order at 11 (Jun. 1, 2017).

[31] Approved by the SCC in Case No. PUE-2009-00081, and by the NCUC in Docket No. E-22, Sub 463.

[32] Approved by the SCC in Case No. PUE-2014-00071 and the proposed extension in Case No. PUR-2017-00129, and by the NCUC in Docket No. E-22, Sub 523).

Figure 5.5.2.1 – Prior IRP Cycle Rejected DSM Programs

Program
Non-Residential HVAC Tune-Up Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
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

5.5.3 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be through methods that raise program awareness as currently conducted in Virginia and North Carolina as discussed in Section 3.2.4.

5.5.4 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.5.4.1 represents approximately 805 GWh in energy savings from DSM programs at a system-level by 2033.

Figure 5.5.4.1 - DSM Energy Reductions

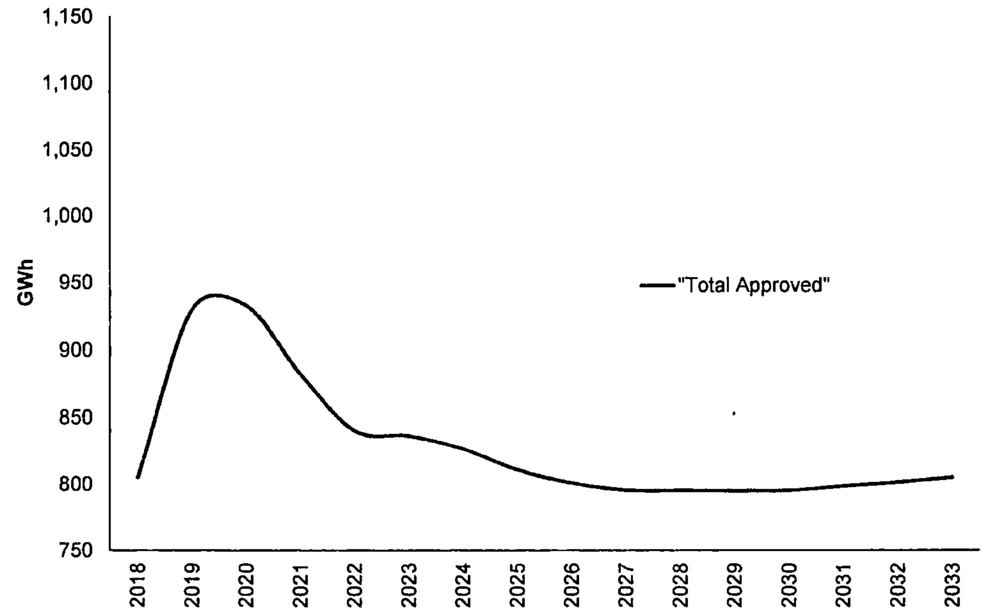
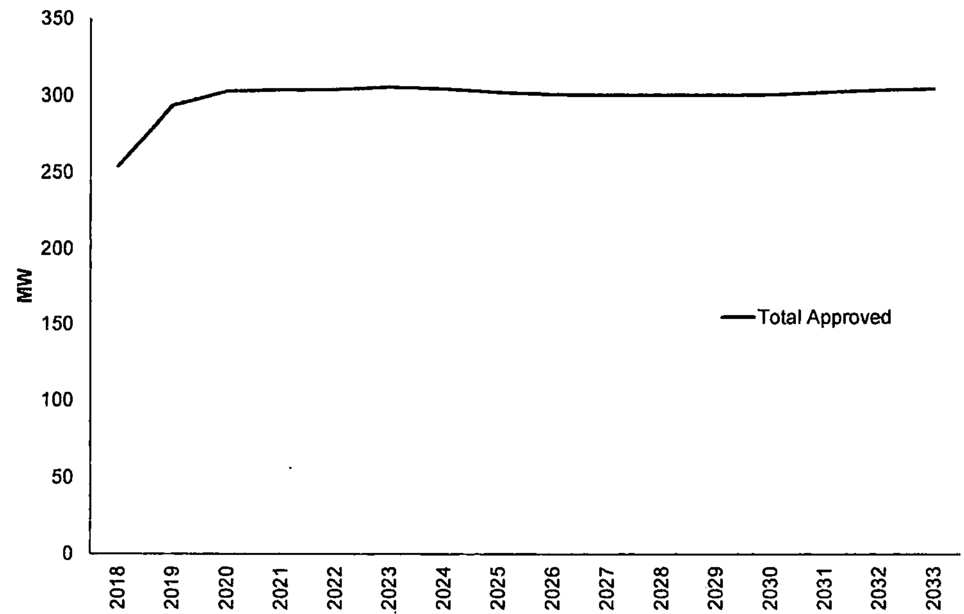


Figure 5.5.4.2 represents a system coincidental demand reduction of approximately 304 MW by 2033 from the DSM programs at a system-level.

Figure 5.5.4.2 - DSM Demand Reductions



The capacity reductions for the portfolio of DSM programs in this 2018 Plan are lower than the projections in the 2017 Plan. The total capacity reduction by the end of the Planning Period was 426 MW for the portfolio of DSM programs in the 2017 Plan and is 304 MW in this 2018 Plan. This represents approximately a 29% decrease in demand reductions.

The energy reduction for the DSM programs by the end of the Planning Period was 1,221 GWh in the 2017 Plan and is approximately 805 GWh in this 2018 Plan. This represents a 34% decrease in energy reductions. The majority of the differences between the 2017 Plan and the 2018 Plan is attributable to the outcome of the 2016 DSM proceeding in Case No. PUE-2016-00111. In that case, the SCC denied the Residential Home Energy Assessment Program and the extension of the DSM Phase II Residential Heat Pump Upgrade Program. In addition, during the course of the proceeding in response to concerns of SCC Staff regarding the Phase IV Non-Residential Prescriptive program, there was a change in the program spend and size, that resulted in reduced average kWh savings. Also, the SCC Staff questioned the inclusion of a refrigeration measure in the DSM Phase V Small Business Improvement Program. The removal of this measure is reflected in current projections in this 2018 Plan.

DSM Levelized Cost Comparison

The Company is providing a comparison of the cost of the Company's expected demand-side management costs relative to its 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 EM&V 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 5.5.4.3.

Figure 5.5.4.3 – Comparison of per MWh Costs of Selected Generation Resources

Comparison of per MWh Costs of Selected Generation Resources to Phase II through Phase VI Programs Utility Cost Perspective	Cost ($/MWh)
Non-Residential Heating and Cooling Efficiency Program	$5.47
Residential Retail LED Lighting Program (NC Only)	$14.70
Non-Residential Lighting Systems and Controls Program	$14.72
Non-Residential Window Film Program	$19.79
Non-Residential Prescriptive Program	$33.12
Solar	$56.38
Small Business Improvement Program	$56.51
2X1 CC	$67.72
1X1 CC	$78.44
Onshore Wind	$94.10
CT	$107.05
Offshore Wind	$130.60
Nuclear	$141.52
Aero CT	$171.54
Fuel Cell	$199.25
Biomass	$221.08
Income and Age Qualifying Home Improvement Program	$237.17
Solar & Aero CT	$248.73
SCPC w/ CCS	$309.93
IGCC w/ CCS	$444.91
CVOW	$779.71

Note: 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 discussed in Section 5.5.1 are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options, and is the method the Company uses to screen DSM programs.

Values shown for these units reflect the Cost of Service method.

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5.5.5 LOAD DURATION CURVES

The Company has provided load duration curves for the years 2019, 2023, and 2033 in Figures 5.5.5.1, 5.5.5.2, and 5.5.5.3, respectively.

Figure 5.5.5.1 - Load Duration Curve 2019

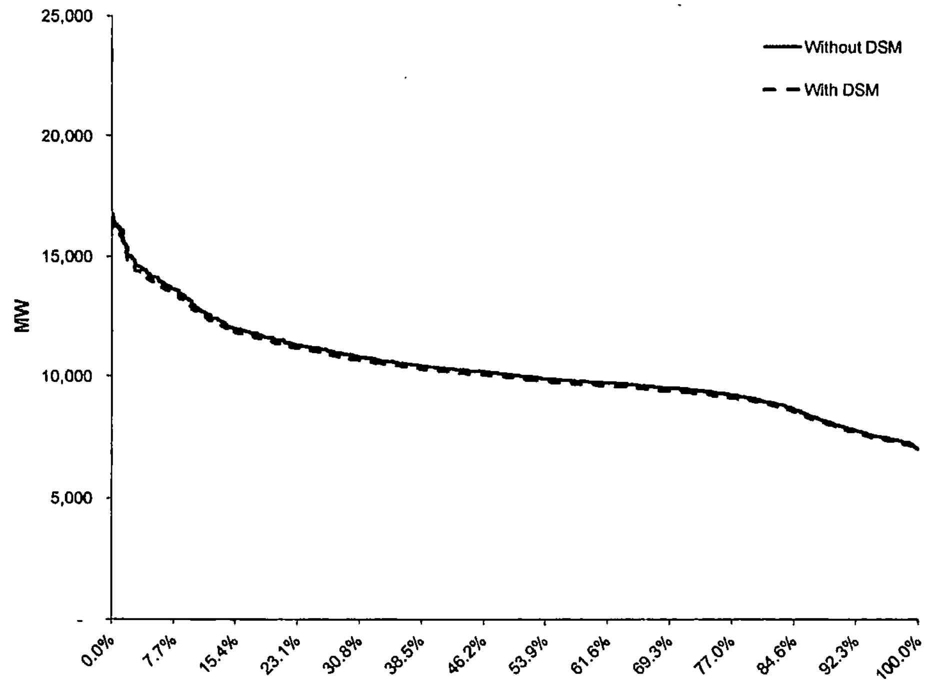


Figure 5.5.5.2 - Load Duration Curve 2023

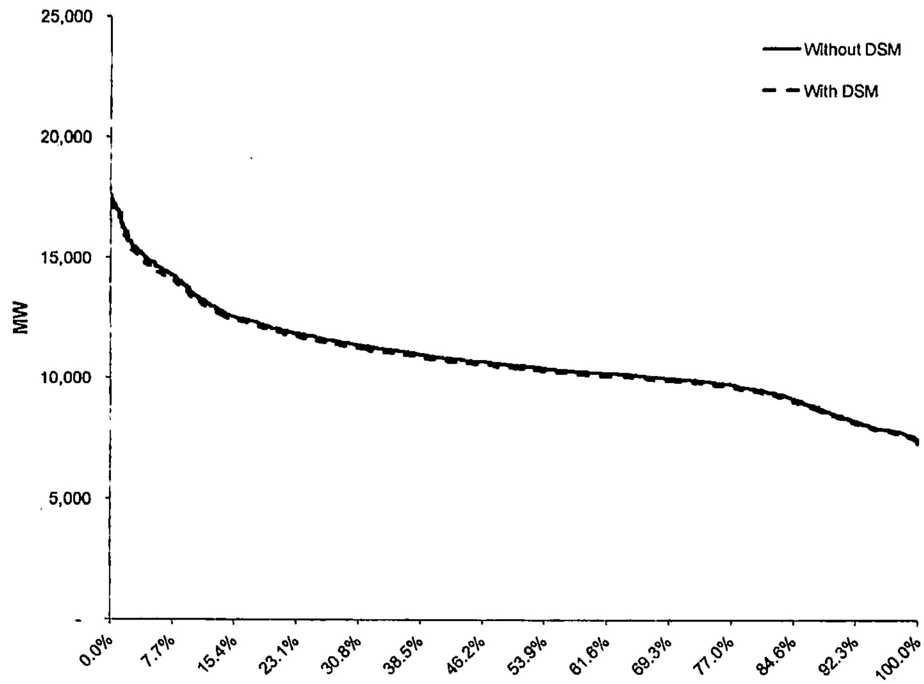
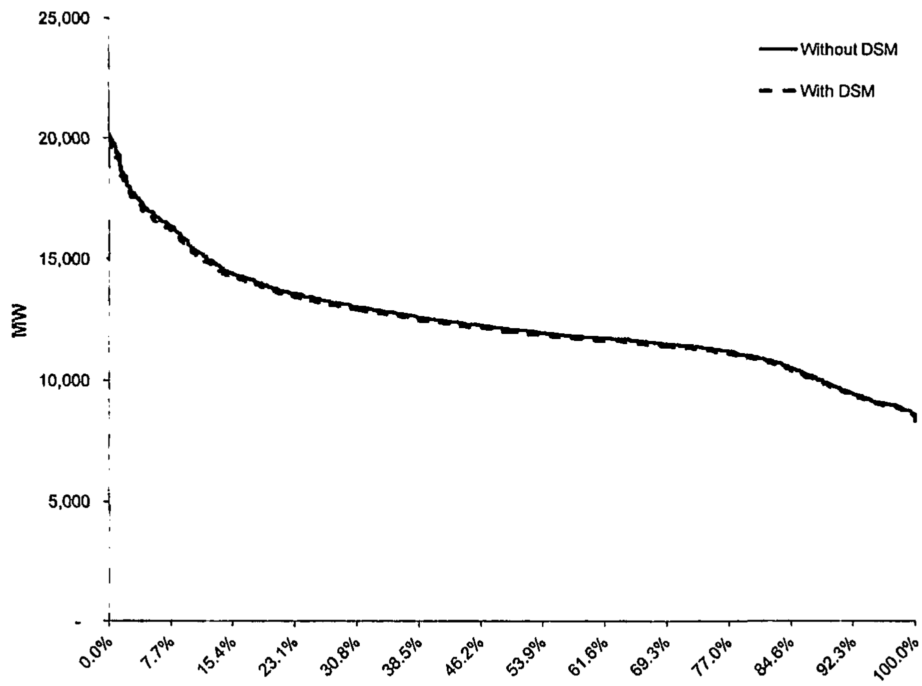


Figure 5.5.5.3 - Load Duration Curve 2033



5.6 FUTURE TRANSMISSION PROJECTS

Figure 7.4.1 provides a list of transmission lines that the Company plans to construct during the Planning Period.

CHAPTER 6 – DEVELOPMENT OF THE INTEGRATED RESOURCE PLAN

6.1 IRP PROCESS

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

The IRP process begins with the development of a long-term annual peak and energy requirements forecast, as described in Chapter 2. Next, existing and approved supply- and demand-side resources, as described in Chapter 3, 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.

As described in Chapter 5, a feasibility screening, followed by a busbar screening curve analysis are conducted to identify supply-side resources, and a cost/benefit screening is conducted 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 Company's planning model, PLEXOS.

The next step is to develop a set of alternative plans using PLEXOS that represent plausible future paths forward considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against plausible scenarios that may occur given future market and regulatory uncertainty.

The Company has included in this 2018 Plan a comprehensive risk analysis in Section 6.7 that quantifies the operating cost risk and project development cost risk of each of the Alternative Plans. This analysis includes a broadband of variables used as forecasting assumptions in this 2018 Plan. These variables include fuel prices, effluent prices, market prices, renewable energy credit costs, construction costs, and the load forecast.

The results of both the cost analysis (PLEXOS modeling) and the comprehensive risk analysis are then compared in order to assess the best path forward to meet the future capacity and energy needs of the Company's customers.

The 2018 Plan development process is detailed in Figure 6.1.1

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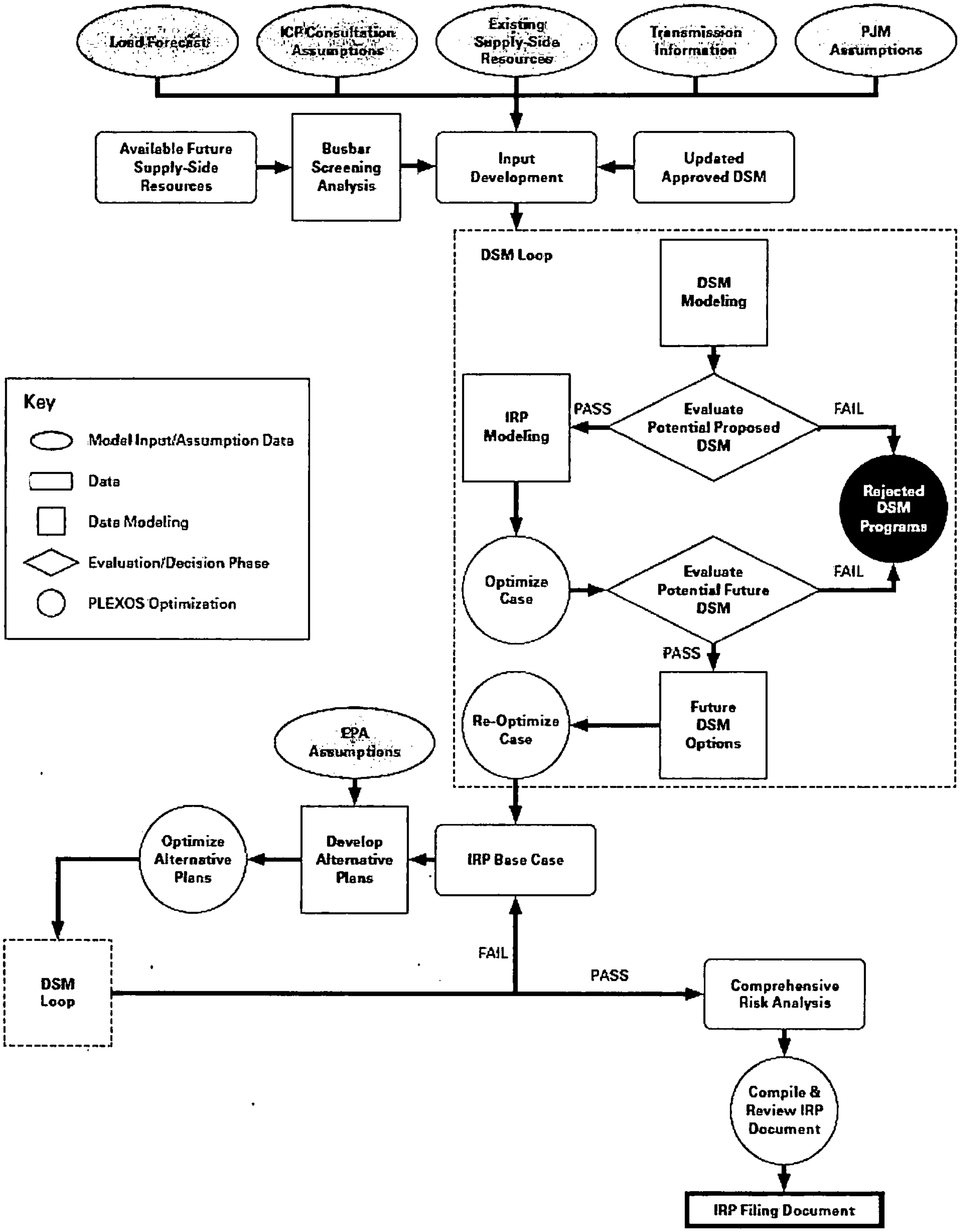
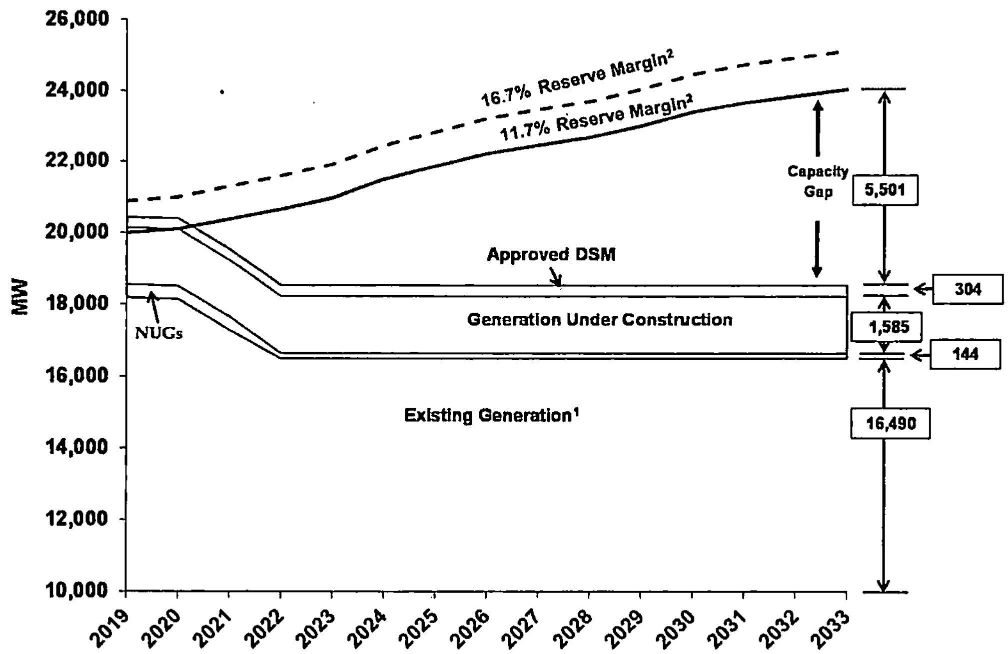
Figure 6.1.1 - Plan Development Process



6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2, over the Planning Period, the Company forecasted average annual growth rates of 1.4% in both peak and energy requirements for the DOM LSE. Chapter 3 presented the Company's existing supply- and demand-side resources, NUG contracts, generation retirements, and generation resources under construction. Figure 6.2.1 shows the Company's supply- and demand-side resources compared to the capacity requirement, including peak load and reserve margin. The area marked as "Capacity Gap" shows additional capacity resources that will be needed over the Planning Period in order to meet the capacity requirement. The Company plans to meet this capacity gap using a diverse combination of additional conventional and renewable generating capacity, DSM programs, and market purchases.

Figure 6.2.1 - Current Company Capacity Position (2019 – 2033)



Note: The values in the boxes represent total capacity in 2033.
1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.
2) See Section 4.2.2.

As indicated in Figure 6.2.1, the capacity gap at the end of the Planning Period is significant. The Planning Period capacity gap is expected to be approximately 5,501 MW. If this capacity deficit is not filled with additional resources, the reserve margin is expected to fall below the required 11.7% planning reserve margin (as shown in Figure 6.2.2) beginning in 2021 and continuing to decrease thereafter.

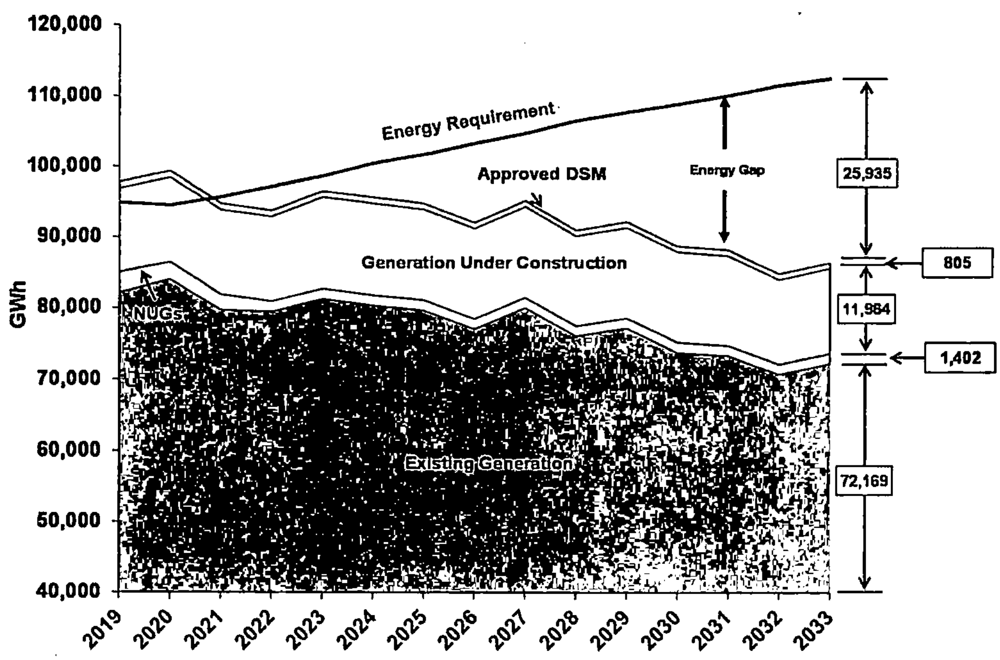
Figure 6.2.2 - Actual Reserve Margin without New Resources

Year	Reserve Margin (%)
2019	13.3%
2020	12.4%
2021	6.1%
2022	-0.8%
2023	-2.3%
2024	-4.7%
2025	-6.3%
2026	-7.8%
2027	-8.8%
2028	-9.7%
2029	-11.0%
2030	-12.5%
2031	-13.4%
2032	-14.1%
2033	-14.8%

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

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

Figure 6.2.3 - Current Company Energy Position (2019 – 2033)



Note: The values in the boxes represent total energy in 2033.
1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

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

6.3 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares the costs of the Alternative Plans to evaluate the type and timing of resources that were included in those plans. The first step in the process was to construct a representation of the Company's current resource base. Then, future assumptions were used as inputs to PLEXOS including but not limited to load, fuel prices, emissions costs, maintenance costs, and resource costs. This analysis provided a set of future supply-side resources potentially available to the Company, along with their individual characteristics. A 3x1 CC was excluded from modeling in the 2018 Plan to prevent future grid stability issues due to the addition of too many large generators in the DOM Zone as well as limited gas availability. The types of supply-side resources that are available to the PLEXOS model are shown in Figure 6.3.1.

Figure 6.3.1 - Supply-Side Resources Available in PLEXOS

Dispatchable
Aero-derivative CT
Biomass
CC 1x1
CC 2x1
Coal w/CCS
CT
Fuel Cell
IGCC w/CCS
Nuclear (NA3)
Non-Dispatchable
CVOW
Offshore Wind
Onshore Wind
Solar NUG
Solar PV
Solar Tag

Key: CC: Combined-Cycle; CT: Combustion Turbine (2 units); IGCC CCS: Integrated-Gasification Combined-Cycle with Carbon Capture and Sequestration; Coal CCS: Coal with Carbon Capture and Sequestration; CVOW: Coastal Virginia Offshore Wind; Solar PV:.Solar Photovoltaic; Solar Tag: Solar PV unit at a brownfield site.

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 2018 Plan. Supply-side options, market purchases, and currently approved demand-side resource options were optimized to arrive at the Alternative Plans presented in this 2018 Plan.

PLEXOS develops optimized resource plans based on the total NPV utility costs over the Study Period while simultaneously adhering to other market drivers, such as price forecasts derived from possible carbon regulations modeled in Plans B, C, D, and E. The NPV utility costs include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

6.4 ALTERNATIVE PLANS

The Company's analysis of the Alternative Plans is intended to represent plausible paths for future resource additions. Each of the Alternative Plans was optimized using least-cost analytical techniques given the constraints associated with that alternative to meet the differing compliance approaches.

Consistent with past Plans, the Company presents five Alternative Plans that represent plausible future paths for meeting the future electric needs of its customers.[33] This 2018 Plan assesses the portfolio expansions necessary to meet compliance with the Virginia RGGI Program (with unlimited imports), with RGGI (with unlimited and with limited imports), and with a potential Federal CO_2 Program consistent with ICF's forecast. As has become custom, the Company has also included an Alternative Plan that estimates future generation expansion in a world where there are no limits on CO_2 emissions.

The Alternative Plans also include the 12 MW (nameplate) CVOW as early as 2021; 760 MW (nameplate) of Virginia and North Carolina solar generation from NUGs, which are currently and expected to be under long-term contracts with the Company by 2020; and the 1,585 MW Greensville County Power Station, which is currently under construction and planned to enter commercial operation by 2019. Lastly, the Alternative Plans include Virginia Company-owned utility-scale solar generation: US-3 Solar 1, 142 MW (nameplate), and US-3 Solar 2, 98 MW (nameplate).

Additionally, the Alternative Plans acknowledge that 10 generating units are being placed into cold reserve in 2018. Bellemeade Power Station, Bremo Power Station Units 3 and 4, and Mecklenburg Power Station Units 1 and 2 were placed into cold reserve in April 2018. Pittsylvania Power Station will be placed into cold reserve in August 2018. Chesterfield Power Station Units 3 and 4 and Possum Point Power Station Units 3 and 4 will be placed into cold reserve in December 2018. "Cold reserve" does not mean permanent retirement. These units are currently planned to remain in cold reserve until 2021. These units, which total 1,292 MW of generation, can be reactivated in approximately six months if system needs and market conditions dictate. The Company will continue to maintain all required environmental permits for the units and continue to pay property taxes to the localities.

The Alternative Plans also assume that all of the Company's existing nuclear generation will receive 20-year license extensions that lengthen their useful lives beyond the Study Period. The license extensions for Surry Units 1 and 2 are included in 2032 and 2033, respectively, and the license extensions for North Anna Units 1 and 2 in 2038 and 2040, respectively.

Figure 6.4.1 reflects the Alternative Plans in tabular format.

[33] As previously discussed, the Company does not consider the CPP a plausible future path. Nevertheless, based on a broad interpretation of the 2017 Plan Final Order, the Company presents a CPP scenario in Appendix 1B.

Figure 6.4.1 – Alternative Plans

Year	Plan A: No CO_2 Tax	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
Approved DSM: 304 MW, 805 GWh by 2033					
2019	Greensville SLR NUG[1]	Greensville SLR NUG[1]	Greensville SLR NUG[1]	Greensville SLR NUG[1]	Greensville SLR NUG[1]
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle[2], Bremo3-4[2] CH3-4[4], MB1-2[2] Pitt[3], PP3-4[4] PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle[2], Bremo3-4[2] CH3-4[4], MB1-2[2] Pitt[3], PP3-4[4] PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle[2], Bremo3-4[2] CH3-4[4], MB1-2[2] Pitt[3], PP3-4[4] PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle[2], Bremo3-4[2] CH3-4[4], MB1-2[2] Pitt[3], PP3-4[4] PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle[2], Bremo3-4[2] CH3-4[4], MB1-2[2] Pitt[3], PP3-4[4] PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT AERO CT SLR (480 MW) CH5-6	CT AERO CT SLR (480 MW) CH5-6	CT AERO CT SLR (480 MW) CH5-6	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (400 MW)
2025	CT SLR (400 MW)	CT AERO CT SLR (400 MW) CL1-2	CT AERO CT SLR (400 MW) CL1-2	2X1 CC SLR (400 MW) CL1-2	CT SLR (480 MW)
2026	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2027	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)
2028	SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)
2029		CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (400 MW)
2030	CT	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (320 MW)
2031	CT SLR (160 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (80 MW)
2032	CT SLR (240 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)	SLR (480 MW)
2033	SLR (80 MW)	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); CT AERO: Aero-derivative CT (119 MW); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.
2) These units entered into cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These units are planned to enter cold reserve in December 2018.

Additional resources and retirements are included in the Alternative Plans below:

Plan A: No CO_2 Tax
Plan A is based on the No CO_2 Tax scenario and is developed using least cost modeling methodology. Specifically, it selects:

- 4,122 MW of CT capacity; and
- 4,480 MW (nameplate) of solar.

Plan B: Virginia RGGI (unlimited imports)
Plan B was designed assuming that the Virginia RGGI Program is finalized as proposed. Specifically, Plan B assumes a partial return of allowance proceeds to generators within Virginia. Plan B assumes that the Company's compliance with RGGI under the Virginia RGGI Program is largely met through the use of imported energy and capacity. Plan B selects:

- 5,038 MW of CT capacity;
- 238 MW of CT Aero capacity;
- 6,400 MW (nameplate) of solar; and
- The retirement of Chesterfield Units 5 and 6 in 2023, and Clover Units 1 and 2 in 2025.

Plan C: RGGI (unlimited imports)
Plan C assumes that Virginia is a full member of RGGI. Specifically, Plan C assumes full auction of RGGI allowances with no return of allowance proceeds to generators within Virginia. Plan C is intended as a comparison against Plan B, and reflects the incremental cost of purchasing all allowances with no offsetting compensation payment. Specifically, Plan C selects:

- 5,038 MW of CT capacity;
- 238 MW of CT Aero capacity;
- 6,400 MW (nameplate) of solar; and
- The retirement of Chesterfield Units 5 and 6 in 2023, and Clover Units 1 and 2 in 2025.

Plan D: RGGI (limited imports)
Plan D assumes that Virginia is a full member of RGGI. Plan D assumes that the Company's compliance with RGGI is met through generation build within Virginia with limited import power. Specifically, Plan D selects:

- 4,122 MW of CT capacity;
- 119 MW of CT Aero capacity;
- 6,400 MW (nameplate) of solar; and
- The retirement of Chesterfield Units 5 and 6 in 2023, and Clover Units 1 and 2 in 2025.

Plan D also includes 1,062 MW of 2x1 CC capacity;

Plan E: Federal CO_2 Program
Plan E anticipates that Virginia does not join RGGI (either directly or through the Virginia RGGI Program) and that federal CO_2 legislation is enacted beginning in 2026. Specifically, Plan E selects:

- 3,664 of CT capacity; and
- 5,760 MW (nameplate) of solar.

Figure 6.4.2 illustrates the renewable resources included in the Alternative Plans over the Study Period (2019 to 2043).

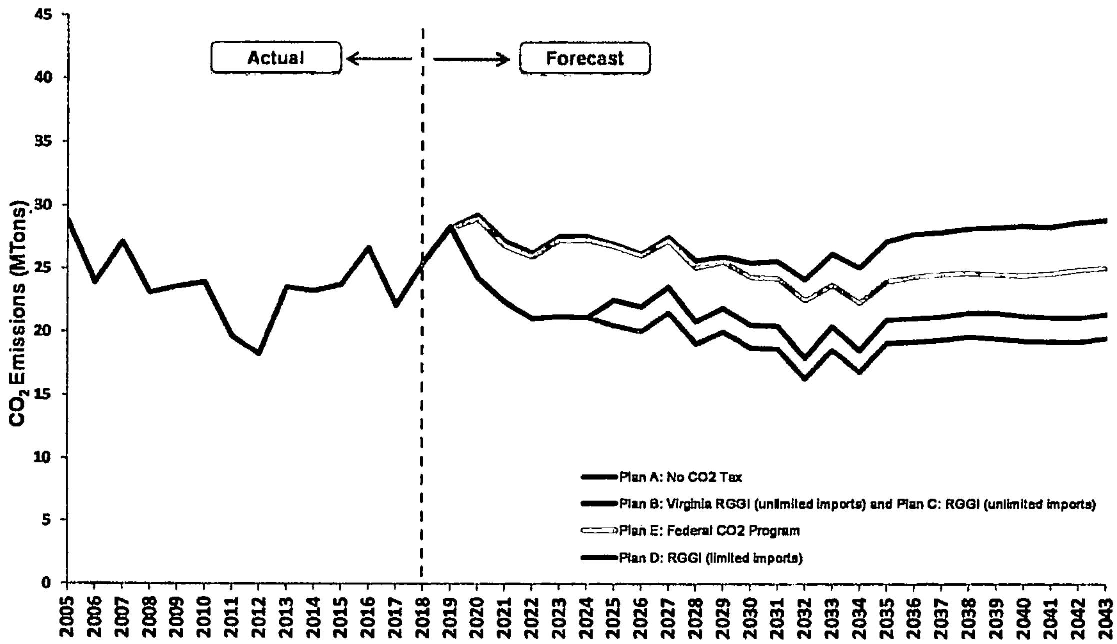
Figure 6.4.2 – Renewable Resources in the Alternative Plans through the Study Period

	Nameplate MW	Plan A: No CO_2 Tax	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
Existing Resources[1]	533	x	x	x	x	x
VCHEC Biomass	61	x	x	x	x	x
Solar NUGs[2]	760	x	x	x	x	x
CVOW	12	x	x	x	x	x
US-3 Solar 1	142	x	x	x	x	x
US-3 Solar 2	98	x	x	x	x	x
Solar PV	Varies	4,960	6,960	6,960	6,960	6,960

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2020.

Figure 6.4.3 shows the total tons of CO_2 emitted for all generation resources including CTs, contracted NUGs, and purchases in each of the Alternative Plans through the Study Period.

Figure 6.4.3 – Virginia CO_2 Output from Dominion Energy Virginia units for the Alternative Plans



Note: Plan B: Virginia RGGI (unlimited imports) and Plan C: RGGI (unlimited imports) have the same build plan and the same amount of CO_2 emissions. The difference between Plans B and C is cost, as shown in Section 6.5.

6.5 ALTERNATIVE PLANS NPV COMPARISON

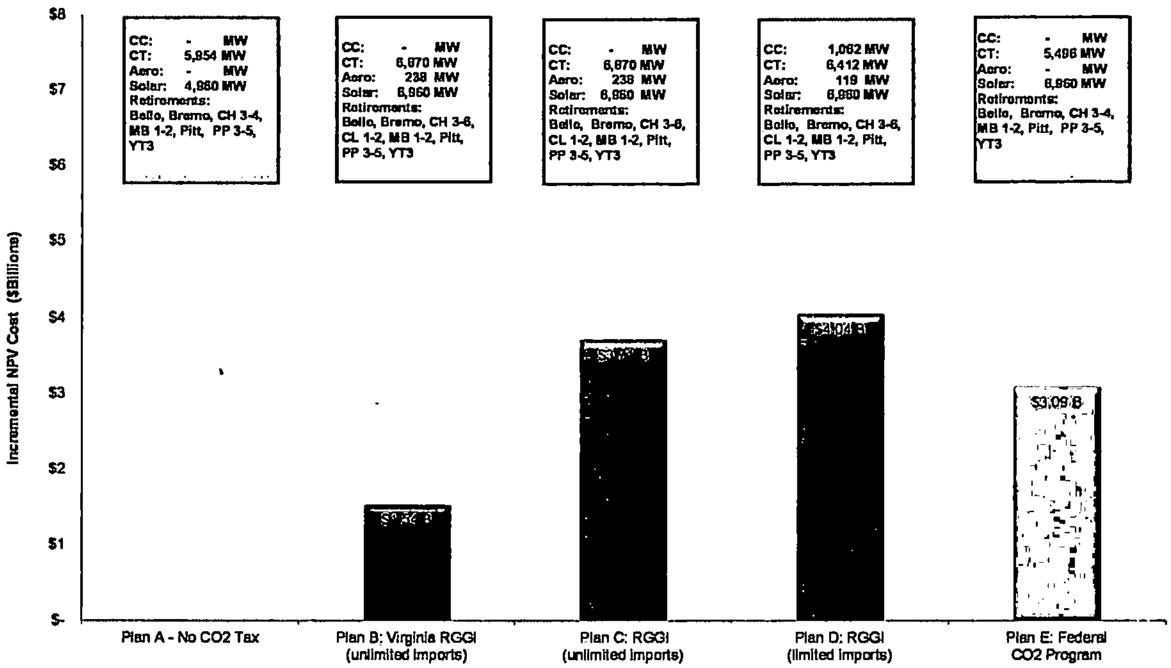
The Company evaluated the Alternative Plans using base-case assumptions to compare and contrast the NPV utility costs over the Study Period. Figure 6.5.1 illustrates the NPV compliance cost for the Alternative Plans by showing the additional expenditures by the Alternative Plans over Plan A for the Study Period.

Figure 6.5.1 – NPV Compliance Cost of the Alternative Plans over Plan A

	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
NPV Compliance Cost ($B)	$ 1.54	$ 3.71	$ 4.04	$ 3.09

Figure 6.5.2 illustrates the incremental NPV compliance cost for the Alternative Plans over Plan A for the Study Period.

Figure 6.5.2 – Incremental NPV Compliance Cost of the Alternative Plans over Plan A (2019 – 2043)



Note: The MWs in this figure do not include CVOW, DSM, Greensville, and US-3 Solar Units 1 and 2.

6.6 RATE IMPACT ANALYSIS

Va. Code § 56-599 B 9 requires the Company to evaluate "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations." Accordingly, the Company evaluated the residential rate impact of each Alternative Plan against Plan A.[34] The results of this analysis are shown in Figures 6.6.1 through 6.6.6, which reflect the nominal dollar impact and percentage increase for a typical residential customer, using 1,000 kWh per month, each year starting in 2020 through 2043. In Plans B, C, and D, the increase in rates in 2023 and 2025 are attributable to the cost write-offs for unit retirements.

In Plan E: Federal CO_2 Program, the decrease in rates in years 2020 through 2026 reflects lower fuel prices in the near-term due to fewer nuclear retirements, more renewable additions, and more coal retirements over the long-term when compared to the Plan A: No CO_2 Tax. The lower fuel prices lead to lower power prices in the near-term.

[34] The Company includes a rate impact analysis of a CPP scenario in Appendix 1B.

Figure 6.6.1 – Monthly Rate Increase of Alternative Plans vs. Plan A

	Increase Compared to Plan A: No CO_2 Tax ($)			
Year	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
2020	0.60	2.17	2.19	(0.24)
2021	0.83	2.34	2.47	(0.34)
2022	1.01	2.54	3.03	(0.30)
2023	10.89	12.49	13.40	(0.34)
2024	2.22	3.86	4.98	(0.30)
2025	6.91	8.55	10.05	(0.28)
2026	3.00	4.66	6.02	(0.02)
2027	3.36	5.21	6.48	0.52
2028	3.87	5.56	6.83	1.76
2029	4.39	6.24	7.29	2.35
2030	4.54	6.34	7.35	2.82
2031	4.73	6.59	7.41	3.53
2032	4.99	6.67	7.40	4.80
2033	4.83	6.84	7.52	5.62
2034	4.77	6.66	7.26	6.66
2035	4.69	6.92	7.37	7.87
2036	4.63	6.95	7.27	8.65
2037	4.39	6.82	7.35	9.21
2038	4.25	6.81	7.42	9.97
2039	4.24	6.88	7.40	10.79
2040	3.95	6.67	6.99	11.68
2041	3.84	6.65	6.90	12.75
2042	3.87	6.77	6.95	14.05
2043	3.60	6.57	6.66	15.46

Figure 6.6.2 – Monthly Rate Increase of Alternative Plans vs. Plan A

	Increase Compared to Plan A: No CO_2 Tax (%)			
Year	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
2020	0.5%	1.9%	1.9%	-0.2%
2021	0.7%	2.0%	2.1%	-0.3%
2022	0.8%	2.1%	2.5%	-0.2%
2023	9.1%	10.4%	11.2%	-0.3%
2024	1.8%	3.2%	4.1%	-0.2%
2025	5.6%	6.9%	8.1%	-0.2%
2026	2.4%	3.7%	4.8%	0.0%
2027	2.6%	4.1%	5.1%	0.4%
2028	3.0%	4.3%	5.3%	1.4%
2029	3.4%	4.8%	5.7%	1.8%
2030	3.5%	4.9%	5.6%	2.2%
2031	3.6%	5.0%	5.6%	2.7%
2032	3.7%	5.0%	5.5%	3.6%
2033	3.5%	5.0%	5.5%	4.1%
2034	3.5%	4.9%	5.3%	4.9%
2035	3.4%	5.1%	5.4%	5.8%
2036	3.4%	5.1%	5.3%	6.3%
2037	3.2%	5.0%	5.4%	6.7%
2038	3.1%	4.9%	5.4%	7.2%
2039	3.1%	5.0%	5.3%	7.8%
2040	2.8%	4.8%	5.0%	8.4%
2041	2.8%	4.8%	4.9%	9.1%
2042	2.8%	4.8%	5.0%	10.0%
2043	2.6%	4.6%	4.7%	10.9%

Figure 6.6.3 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A

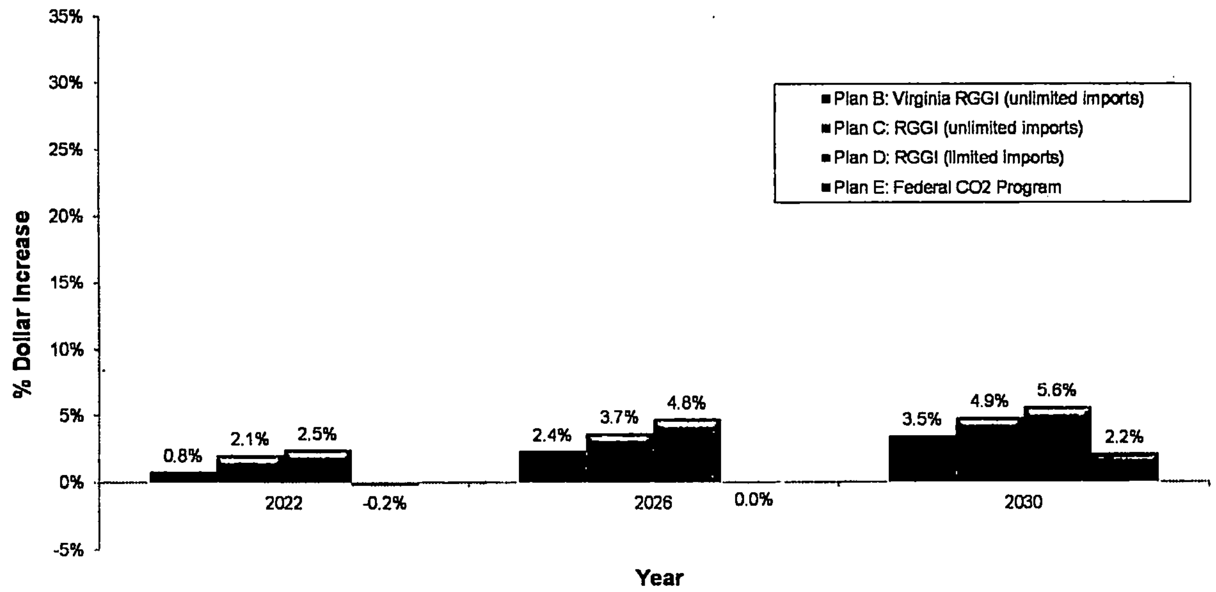


Figure 6.6.4 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A

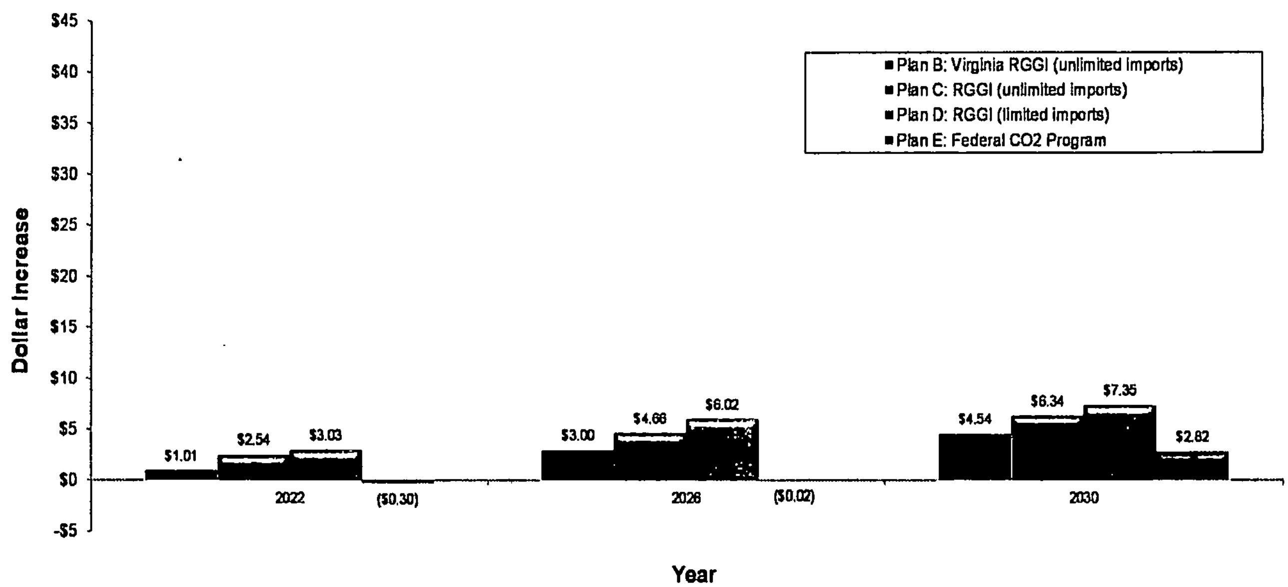


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Figure 6.6.5 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A

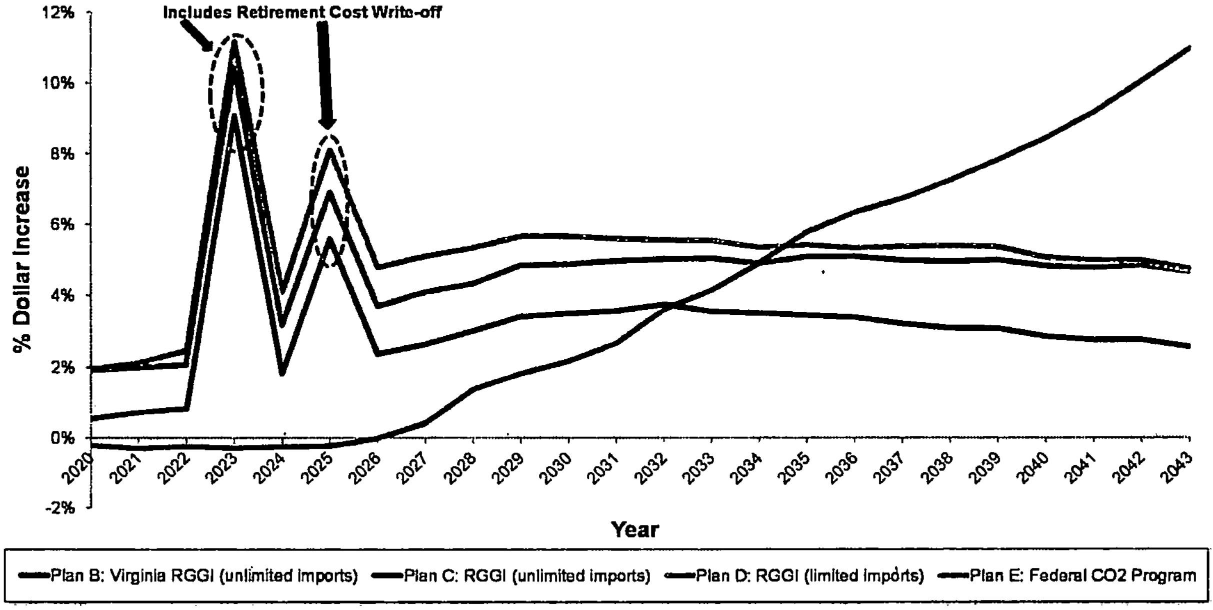
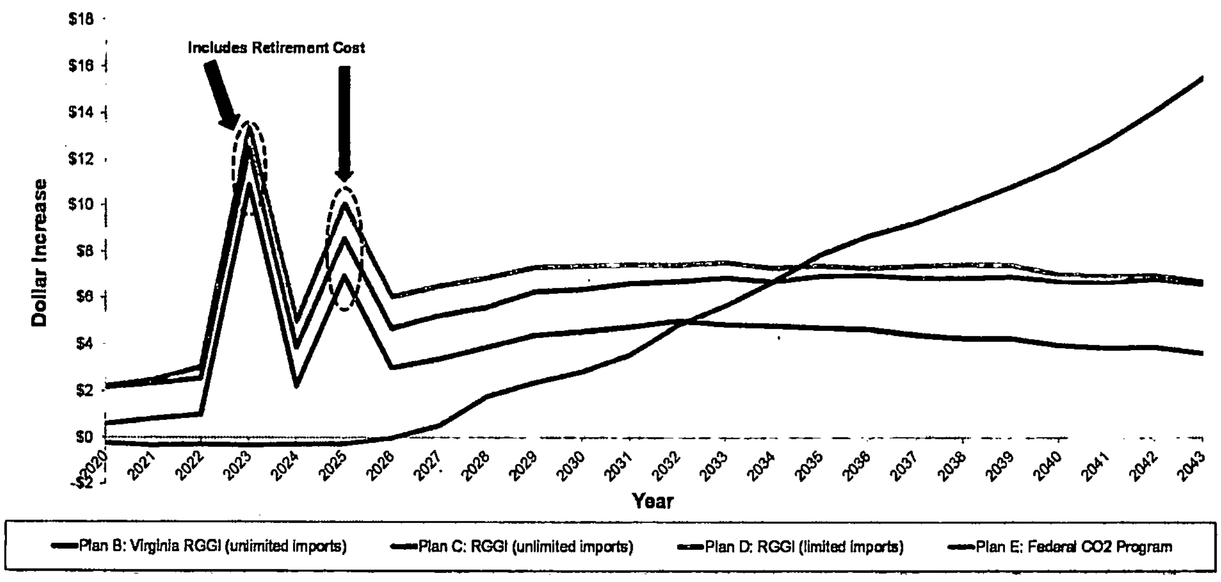


Figure 6.6.6 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A



6.7 COMPREHENSIVE RISK ANALYSIS

6.7.1 OVERVIEW

To evaluate the risks associated with the Alternative Plans presented in Section 6.4, this 2018 Plan includes a comprehensive risk analysis methodology. Similar to the 2017 Plan, the Company utilized the same stochastic (probabilistic) methodology and supporting software developed by Pace Global (a Siemens business) in concert with the AURORA multi-area production costing model (licensed from EPIS, Inc.). Using this analytic and modeling framework (hereinafter referred to as the "Pace Global Methodology"), the Alternative Plans, each treated as a fixed portfolio of existing and expansion resources plus DSM measures, were evaluated and compared on the dimensions of average total production cost relative to two measures of cost-related risk: (i) standard deviation cost and (ii) semi-standard deviation cost.

The Pace Global Methodology is an adaptation of modern portfolio theory, which attempts to quantify the trade-off that usually exists between portfolio cost and portfolio risk, a quantification that is not addressed in the traditional least-cost planning paradigm. Measuring the risk associated with proposed expansion plans quantifies, for example, whether adopting any one particular plan comes with greater cost and risk for customers when compared to the cost and risk for competing plans. In the same way, comparing plans with different capacity mixes—which have different cost and risk profiles—potentially reveals the value of generation mix diversity. Importantly, it is impractical to include all possible sources of risk in this assessment, so the assessment includes only the most significant drivers to plan cost and variability.

At a high level, the Pace Global Methodology is comprised of the following steps:

1. Identify and create a stochastic model for each key source of portfolio risk which in this analysis are:
   - Natural gas prices;
   - Natural gas basis;
   - Coal prices;
   - Oil prices (for proxy of coal transportation cost);
   - Load (electricity demand);
   - Hourly solar generation;
   - CO_2 emission allowance prices; and
   - New generation capital cost.

2. Generate a set of stochastic realizations for the key risk factors within the PJM region and over the Study Period using Monte-Carlo techniques. For purposes of this analysis, 200 stochastic realizations were produced for each of the key risk factors.
3. Subject each of the Alternative Plans separately to this same set of stochastic risk factor outcomes by performing 200 AURORA multi-area model production cost simulations, which cover a significant part of the EI, using the risk factor outcomes as inputs.
4. Use the AURORA simulation results to calculate the expected levelized all-in average cost and the associated risk measures for each of the Alternative Plans.

The following Alternative Plans were evaluated under the comprehensive risk analysis:

- Plan A: No CO_2 Tax
- Plan B: Virginia RGGI (unlimited imports)
- Plan C: RGGI (unlimited imports)
- Plan D: RGGI (limited imports)
- Plan E: Federal CO_2 Program

6.7.2 PORTFOLIO RISK ASSESSMENT

Upon completion of the AURORA simulations described in Section 6.7.1 post-processing of each Alternative Plan's annual average total (fixed plus variable) production costs proceeded in the following steps:

- Levelize the annual average total production costs for each of the 200 draws over the 25-year Study Period using a nominal discount rate of 6.31%.
- Statistically summarize the 200 levelized average total production costs values into:
  - **Expected value**: the arithmetic average value of the 200 draws.
  - **Standard deviation**: the square-root of the average of the squared differences between each draw's levelized value and the mean of all 200 levelized values. This is a standard measure of overall cost risk to the Company's customers.
  - **One way (upward) standard deviation (semi-standard deviation)**: the standard deviation of only those levelized average production costs which exceed the expected value (i.e., the mean of all 200 levelized values). This is a measure of adverse cost risk to the Company's customers.

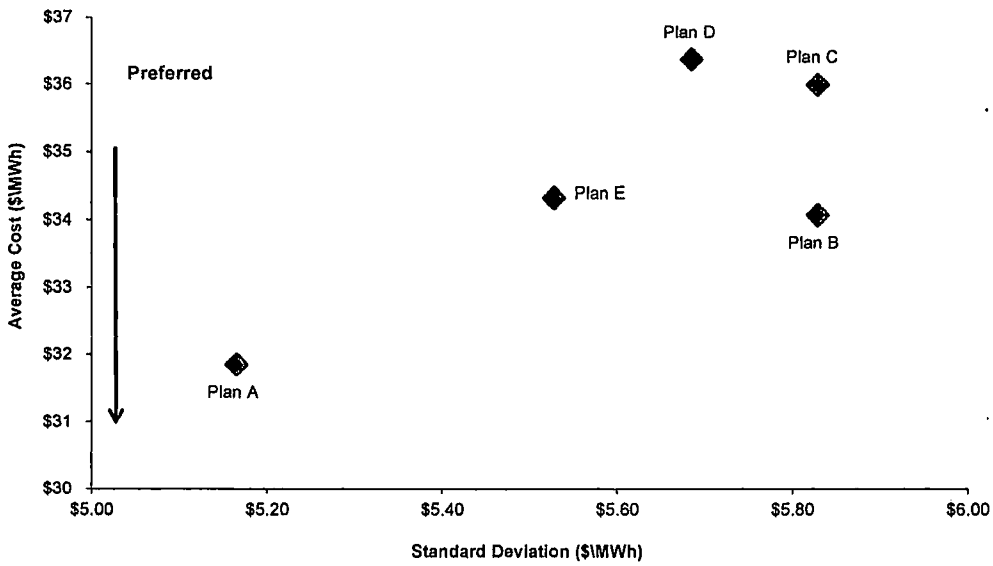
The resulting values are shown for the Alternative Plans in Figure 6.7.2.1 for comparative purposes. Plans with lower values for expected levelized average cost, standard deviation, and semi-standard deviation are more beneficial for customers.

Figure 6.7.2.1 - Alternative Plan Portfolio Risk Assessment Results

2018 \$/MWh Plan	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan A: No CO_2 Tax	\$31.84	\$5.16	\$5.73
Plan B: Virginia RGGI (unlimited imports)	\$34.06	\$5.83	\$6.36
Plan C: RGGI (unlimited imports)	\$35.98	\$5.83	\$6.36
Plan D: RGGI (limited imports)	\$36.36	\$5.68	\$6.17
Plan E: Federal CO_2 Program	\$34.32	\$5.53	\$5.91

Plan A: No CO_2 Tax had the lowest levelized average cost and risk of all Alternative Plans. This result is expected given that Plan A was evaluated in a future that assumes no new CO_2 regulation in any state, including Virginia. Among all other Alternative Plans with different regulations on carbon emissions, Plan B: Virginia RGGI (unlimited imports) had the lowest expected cost and Plan E: Federal CO_2 Program had the lowest risk based on the standard deviation. A visual display of average cost against risk as measured by standard deviation for the Alternative Plans is shown in Figure 6.7.2.2.

Figure 6.7.2.2 – Alternative Plans Mean-Variance Plot



6.7.3 INCLUSION OF THE DISCOUNT RATE AS A CRITERION IN RISK ANALYSIS

The Company also included discount rate as a criterion in its risk analysis. As described in Section 6.4, each of the Alternative Plans was developed based on minimization of total NPV utility costs over the Study Period subject to constraints, such as the reserve margin target and different regulations on carbon emissions. The discount rate is a key parameter in the NPV calculation and plays an important role in computing the risk analysis results. The Company notes the following points to form a background for the discussion on the discount rate:

- In principle, the appropriate discount rate to evaluate alternative expansion plans is from the standpoint of utility customers collectively, not the utility. While the customer discount rate is unobservable, it is a function of the opportunity costs facing utility consumers. This rate would be the same regardless of the expansion plan being evaluated. Absent knowledge of the customer discount rate, it is not unreasonable to use the utility discount rate as a proxy.
- In developing the Alternative Plans and in the comprehensive risk analysis, the discount rate used is the Company's five-year forecasted nominal after-tax weighted average cost of capital ("WACC"). This same discount rate is applied regardless of the expansion options under consideration. In this way, NPV costs are calculated on a consistent basis across all Alternative Plans. Because risk simulation results are in nominal 2018 dollars, after-tax WACC is used to levelize the average production costs over the Study Period for each of 200 stochastic realizations.
- Capital revenue requirements projected for each generation expansion option include EPC costs, capitalized financing costs, and equity return incurred prior to commercial operation.
- The comprehensive risk analysis results include the effect of uncertainty in the levelized capital revenue requirements for each type of expansion option. The risk analysis assumed the greatest uncertainty was for new nuclear and offshore wind projects and the least uncertainty was for technologies for which there is a lower per project capital requirements and/or for which the Company has proven construction experience.

Inclusion of the discount rate as a risk criterion is advisable because expansion plans that include significantly large and risky future capital outlays could mean that investors would require higher returns in compensation for the larger amount of capital at risk. It may also imply potentially significant changes in the Company's future capital structure because the appropriate discount rate would be higher than that for Alternative Plans comprised of less capital intensive or risky projects. Therefore, using a higher discount rate for such Alternative Plans would have the incorrect and implausible result of yielding lower expected NPV costs.

An alternative approach is to apply a risk-adjusted discount rate to the Alternative Plans that include high capital costs or high risk projects. Determining the appropriate risk-adjustment to the discount rate is problematic and is not known by the Company. For the present purpose of including the discount rate as a criterion in the risk analysis, Figures 6.7.3.1 and 6.7.3.2 show the results before and after a zero discount rate is applied to Plan D: RGGI (limited imports), which has the highest NPV cost of the Alternative Plans, and Plan C: RGGI (unlimited imports), which has the highest standard deviation of the Alternative Plans. Using a zero discount rate attributes the maximum possible degree of risk adjustment to the discount rate for these two Alternative Plans and therefore provides an upper bound for such risk-adjusted discounting.

Figure 6.7.3.1 – Plan D: RGGI (limited imports) Risk Assessment Results

2018 Plan $/MWh	Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan D: RGGI (limited imports) - not risk adjusted	$36.36	$5.68	$6.17
Plan D: RGGI (limited imports) - risk adjusted	$42.25	$7.76	$9.07

Figure 6.7.3.2 – Plan C: RGGI (unlimited imports) Risk Assessment Results

2018 Plan $/MWh	Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan C: RGGI (unlimited imports) - not risk adjusted	$35.98	$5.83	$6.36
Plan C: RGGI (unlimited imports) - risk adjusted	$41.99	$7.98	$9.28

Based on these numbers, it is evident that on a risk-adjusted basis, Plan D: RGGI (limited imports) still has the largest expected average production cost, while Plan C: RGGI (unlimited imports) still has the largest risk measured by both standard deviation and semi-standard deviation among all Alternative Plans.

While the Company includes this discount rate analysis, none of the Alternative Plans in this 2018 Plan includes what the Company believes to be capital-intensive high-risk generation, such as new nuclear units.

6.7.4 IDENTIFICATION OF LEVELS OF NATURAL GAS GENERATION WITH EXCESSIVE COST RISKS

The SCC has directed the Company to specifically identify the levels of natural gas-fired generation where operating cost risks may become excessive or provide a detailed explanation as to why such a calculation cannot be made." In this 2018 Plan, each of the Alternative Plans was developed to comply on a standalone basis with different forms of carbon emission regulation. The results of the comprehensive risk analysis reflect the expected cost and estimated risk associated with each Alternative Plan in the context of a no carbon emission regulation or a particular mode of regulation. In developing each of the Alternative Plans, the criterion used was minimization (subject to constraints) of NPV costs without considering the associated level of risk. Alternative Plan risk levels were assessed only after it was determined to be the lowest cost from among all feasible candidate plans. Developing Alternative Plans that considered both cost and risk jointly as criteria would have required the following different process:

- The expansion planning process would have to determine the "efficient frontier" from among all feasible candidate plans. The efficient frontier identifies a range of feasible plans each with the lowest level of risk for its given level of expected cost. Identifying the efficient frontier is not practical using traditional utility planning software and computing resources. If the efficient frontier could be determined, then any candidate plan with risk levels higher than the efficient frontier could reasonably be characterized as having excess risk in the sense that there exists a plan on the efficient frontier with the same expected cost but with lower risk.
- The Company would need to know the "mean-variance utility function" (i.e., the risk aversion coefficient) of its customers collectively in order to select the feasible plan that optimally trades off cost and risk from among competing plans. This function could be applied regardless of whether it is possible to determine the efficient frontier. However, this function is <u>not</u> known, meaning that planners are unable to determine levels of plan risk that are unacceptable or that become excessive for customers.

In the absence of these risk evaluation tools, it is not technically possible to determine an absolute level of plan risk that becomes excessive, much less to determine that level of gas-fired generation within a plan that poses excessive cost risk for customers. Moreover, the absolute level of natural gas generation within a plan does not necessarily lead to greater risk; rather, all else being equal, it is the degree of overall supply diversity that drives production cost risk.

Because the notion of excessive risk is inherently relative, Company planners can apply a ranked preference approach through which a plan is preferred if its expected cost and measured risk are both less than the corresponding values of any competing plan. The ranked preference approach does not need to rely on a definition of excessive risk, but only on the principle that customers should prefer a plan that is simultaneously lowest in cost and in risk among competing plans. In the 2018 Plan, the results of the comprehensive risk analysis show that Plan A: No CO_2 Tax has the lowest expected cost and risk than any of the other Alternative Plans. However, Plan A does not assume any regulation on carbon emissions and may not be preferred on grounds unrelated to risk. But, comparing Plan B: Virginia RGGI (unlimited imports) with Plan E: Federal CO_2 Program shows that Plan E has somewhat lower risk than Plan B, but with a slightly higher expected cost. In this case, it is not clear which of the two Plans should be preferred. The planner could apply a mean-variance utility function (i.e., the customer risk aversion coefficient), if known, to ultimately determine which Alternative Plan is preferable. Without this coefficient, however, it can be reasonably assumed that Plan B would be preferable because it is lower cost with approximately the same level of risk.

6.7.5 OPERATING COST RISK ASSESSMENT

The Company analyzed ways to mitigate operating cost risk associated with natural gas-fired generation through the use of long-term supply contracts that lock in a stable price, long-term investment in gas reserves, long-term firm transportation, and on-site liquefied natural gas storage.

Supply Contract/Investment in Gas Reserves

For the purpose of analyzing long-term supply contracts and long-term investments in gas reserves, the Company utilized the stochastic analysis to determine the reduction in volatility that can be achieved by stabilizing prices on various volumes of natural gas. The expected price of natural gas as determined by the stochastic analysis is utilized to stabilize market price for this analysis. To analyze operating cost risk of such price stabilizing arrangements the price of natural gas is "fixed" at the expected value prices for a portion of the total fueling needs. The evaluation measures the reduction in plan risk by comparing the standard deviation between a plan with various quantities of "fixed" price natural gas and the same plan without "fixed" price natural gas. This methodology is representative of measuring the impact of a long-term supply contract and/or long-term investment in gas reserves on overall plan risk. In either case, the actions would simulate committing to the purchase of natural gas supply over a long term at prevailing market prices at the time of the transaction. The primary benefit of such a strategy is to stabilize fuel prices, not to ensure below-market prices. Figures 6.7.5.1 through 6.7.5.4 indicate the reduction in portfolio risk associated with various quantities of natural gas at fixed price contracts or a natural gas reserve investment.

Figure 6.7.5.1 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – No Natural Gas at Fixed Price

No Natural Gas at Fixed Price			
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation
Plan A: No CO_2 Tax	$31.84	$5.16	$5.73
Plan B: Virginia RGGI (unlimited imports)	$34.06	$5.83	$6.36
Plan C: RGGI (unlimited imports)	$35.98	$5.83	$6.36
Plan D: RGGI (limited imports)	$36.36	$5.68	$6.17
Plan E: Federal CO_2 Program	$34.32	$5.53	$5.91

Figure 6.7.5.2 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 10% of Natural Gas at Fixed Price

10% of Natural Gas at Fixed Price				
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Tax	$31.89	$4.74	$5.28	8.2%
Plan B: Virginia RGGI (unlimited imports)	$34.10	$5.47	$5.97	6.1%
Plan C: RGGI (unlimited imports)	$36.01	$5.47	$5.97	6.1%
Plan D: RGGI (limited imports)	$36.39	$5.31	$5.76	6.5%
Plan E: Federal CO_2 Program	$34.35	$5.12	$5.49	7.3%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Figure 6.7.5.3 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 20% of Natural Gas at Fixed Price

20% of Natural Gas at Fixed Price				
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Tax	$31.99	$4.31	$4.80	16.5%
Plan B: Virginia RGGI (unlimited imports)	$34.17	$5.17	$5.66	11.4%
Plan C: RGGI (unlimited imports)	$36.08	$5.12	$5.60	12.1%
Plan D: RGGI (limited imports)	$36.47	$4.95	$5.38	13.0%
Plan E: Federal CO_2 Program	$34.45	$4.72	$5.03	14.6%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Figure 6.7.5.4 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 30% of Natural Gas at Fixed Price

2018 Plan $/MWh	30% of Natural Gas at Fixed Price Expected Levelized Average Cost	Standard Deviation	Semi-Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Tax	$32.15	$3.89	$4.32	24.6%
Plan B: Virginia RGGI (unlimited imports)	$34.29	$4.77	$5.18	18.1%
Plan C: RGGI (unlimited imports)	$36.21	$4.77	$5.18	18.1%
Plan D: RGGI (limited imports)	$36.60	$4.58	$5.00	19.4%
Plan E: Federal CO_2 Program	$34.60	$4.32	$4.59	21.8%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Included in the analysis of cost and risk mitigation effects of the long-term contracts or reserve investment is an estimate of the price impact the purchase of a large volume of natural gas would have on the market. The cost of such a transaction used in this analysis are representative of the impact on upward price movement that is likely to occur in the market for natural gas with the purchase of a significant quantity of gas on a long-term basis. The market impact of transacting significant volumes on a long-term contract is a function of the amount of time required to execute the contract volume and the price impact/potential movement of the price strip contract during the execution time. The cost of executing a contract of this type is estimated using the price of gas, the daily volatility of the five-year price strip, and the number of days needed to procure the volume. The larger the volume, the longer it takes to execute the transaction, which exposes the total transaction volume to market volatility for a longer period of time and thereby increases the potential for increased cost associated with the transaction. The estimated cost adders included in the analysis are summarized in Figure 6.7.5.5.

Figure 6.7.5.5 – Cost Adders for a Fixed Price Natural Gas Long-Term Contract ($/MMbtu)

		Yearly Volume (Bcf)			
		25	50	75	100
Gas Price	$3.00	$0.08	$0.13	$0.18	$0.23
	$5.00	$0.11	$0.20	$0.28	$0.36
	$7.00	$0.15	$0.26	$0.38	$0.49

The analyzed volumes will have an impact on forward market prices; as such, the Company considers it prudent to include an estimate of the impact of transactions involving large volumes of natural gas on the gas price as a cost adder in this analysis. The Company recognizes the actual impact may be higher or lower than estimated. These costs are presented as representative based on assumptions determined from current market conditions. The salient value to these estimates is the inclusion of estimated market impact verses assuming the transactions can be conducted with no market price impact.

The primary benefit of such a strategy is to mitigate fuel price volatility, not to ensure below market prices. Stable natural gas pricing over the long term does have advantages in terms of rate stability but also carries the risk of higher fuel cost should the market move against the stabilized price. Figures 6.7.5.6 and 6.7.5.7 provide a hypothetical example of stabilizing natural gas price at prevailing market prices available in February 2011 and February 2012, respectively. In this simplified example the assumption is a total fuel volume of 100 million cubic feet ("mmcf") per day is needed for the entire period. The analysis then evaluates the impact of stabilizing the natural gas price (using February 2, 2011 and February 2, 2012 forward curves) for 20% of the volume against allowing the total volume to be priced at daily market prices. The key parameter is the cumulative difference between programs that stabilize the price of 20% of the natural gas volume while purchasing 80% of the volume at daily market prices versus purchasing all the natural gas at daily market prices for the entire term. In these examples, the cumulative cost of the natural gas purchased by the 20% fixed cost program are higher by 6% to 14% depending on when the contract was established. These examples indicate that although the use of long-term contracts or reserve investments provides an effective method for mitigating fuel prices volatility, it does not ensure lower fuel cost to the customer.

Figure 6.7.5.6 – Hypothetical Example of the Cost of Purchasing 100 MMcf/day of Natural Gas

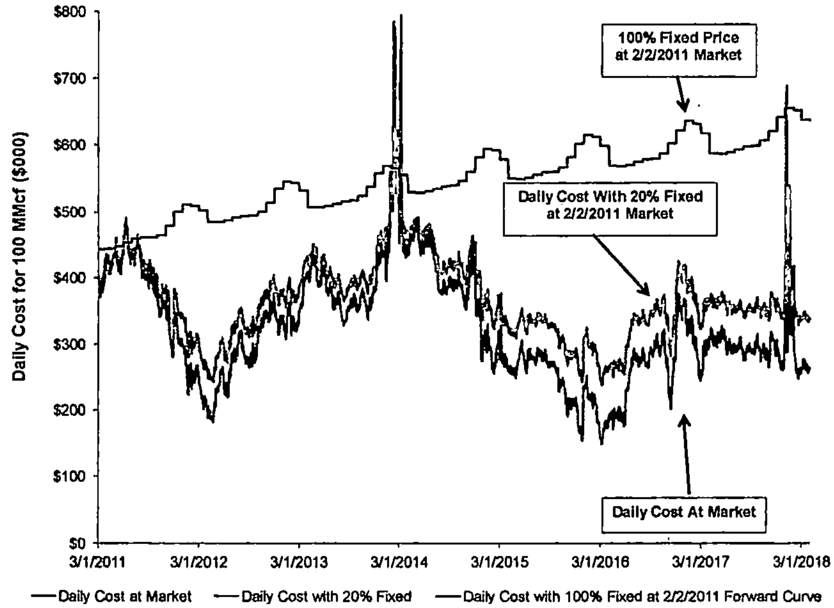
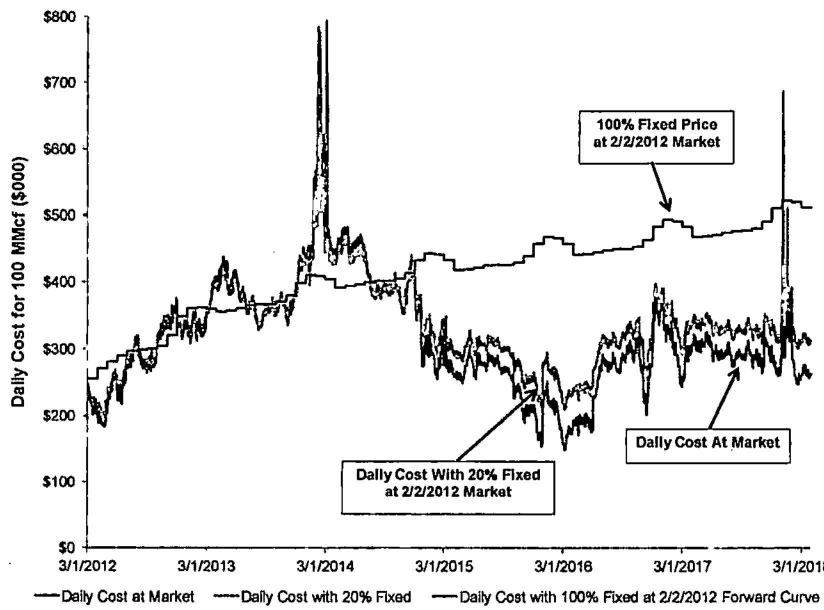


Figure 6.7.5.7 – Hypothetical Example of the Cost of Purchasing 100 MMcf/day of Natural Gas



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Firm Transportation
To evaluate the risk mitigation impact of securing long-term firm transportation, historic prices were analyzed at two natural gas supply basin trading hubs, Henry Hub and South Point, and at a natural gas trading hub representative of the Company's service territory, Transco Zone 5. The risk mitigation impact is a function of the difference in volatility between various natural gas trading hubs. Pipeline constraints can limit the ability of the pipeline network to move natural gas from supply basins to the market area. These constraints, coupled with weather-driven demand, have historically resulted in significant location specific price volatility for natural gas. Long-term transportation contracts to various supply basin trading hubs afford the opportunity to mitigate location specific volatility risk by having the option to purchase natural gas at trading hubs that have less volatile pricing characteristics. Figure 6.7.5.8 shows the location of key natural gas trading hubs. Figures 6.7.5.9 through 6.7.5.11 illustrate the historic price variations (2009 to March 2018) for natural gas at three trading hubs. The shaded area of the graphs indicates one standard deviation of pricing history for each year, meaning that 68% of all daily prices for each year fall within the shaded area. As can be seen in these figures, the historic variations in price differ between the three trading hubs with Transco Zone 5 having a higher variation in natural gas prices than the two trading hubs located in supply basins. Based on historic pricing patterns, this would indicate a long-term transportation contract to either Henry Hub or South Point would provide the opportunity to purchase natural gas at a trading hub that has historically experienced less short-term variations in price.

Figure 6.7.5.8 – Map of Key Natural Gas Pipelines and Trading Hubs

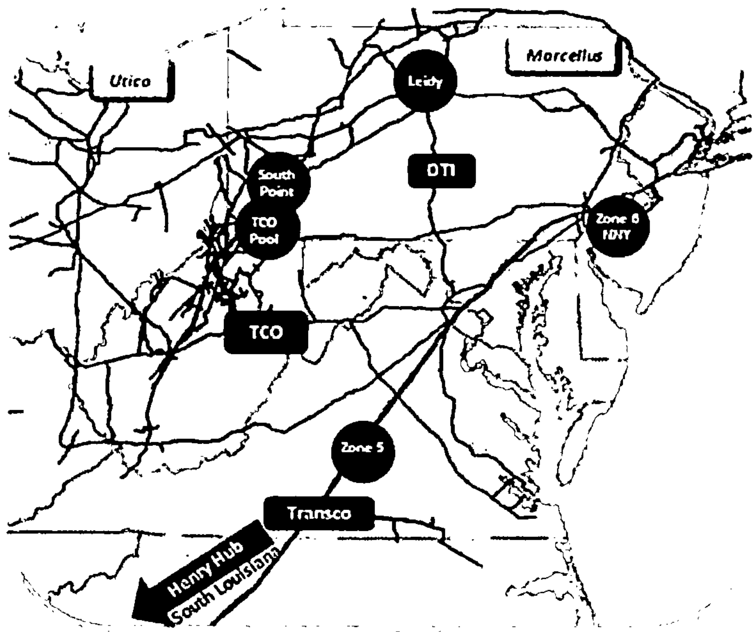

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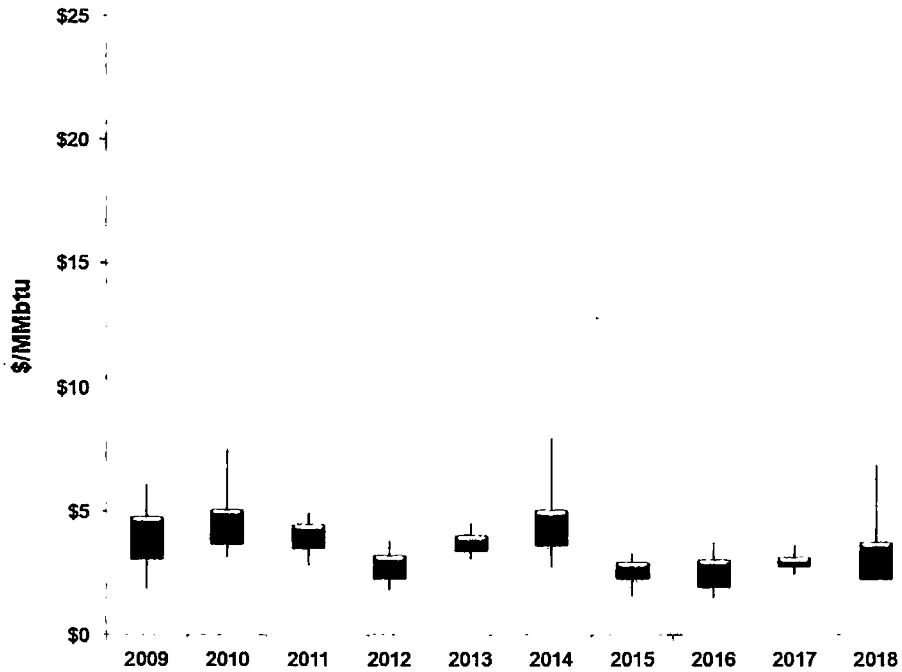
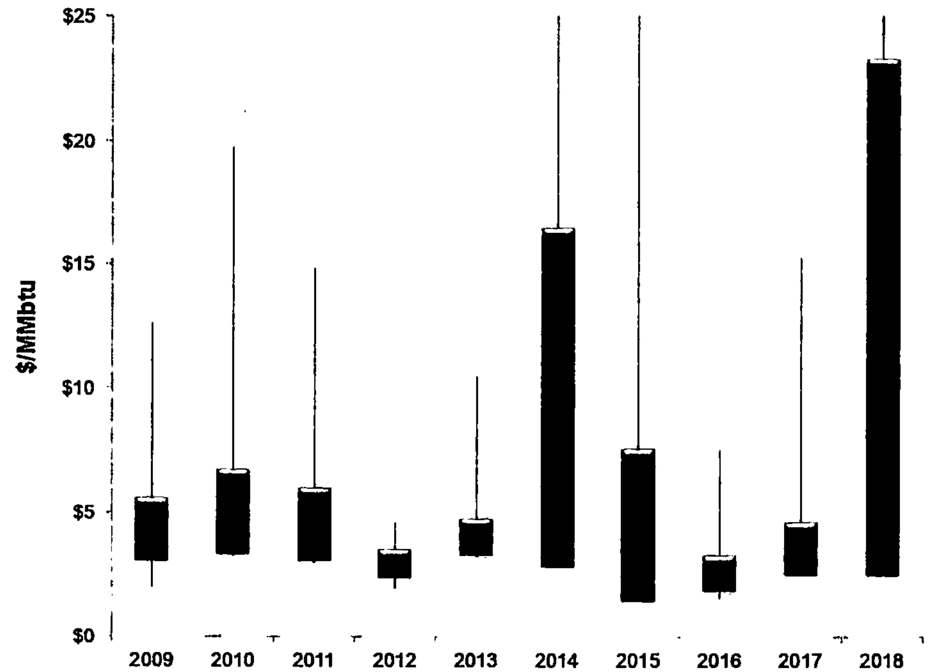
Figure 6.7.5.9 – Natural Gas Daily Average Price Ranges – Henry Hub



Note: A larger box indicates greater price volatility than a smaller box. Prices through March 31, 2018.

Figure 6.7.5.10 – Natural Gas Daily Average Price Ranges – Transco Zone 5



Note: A larger box indicates greater price volatility than a smaller box. Prices through March 31, 2018.

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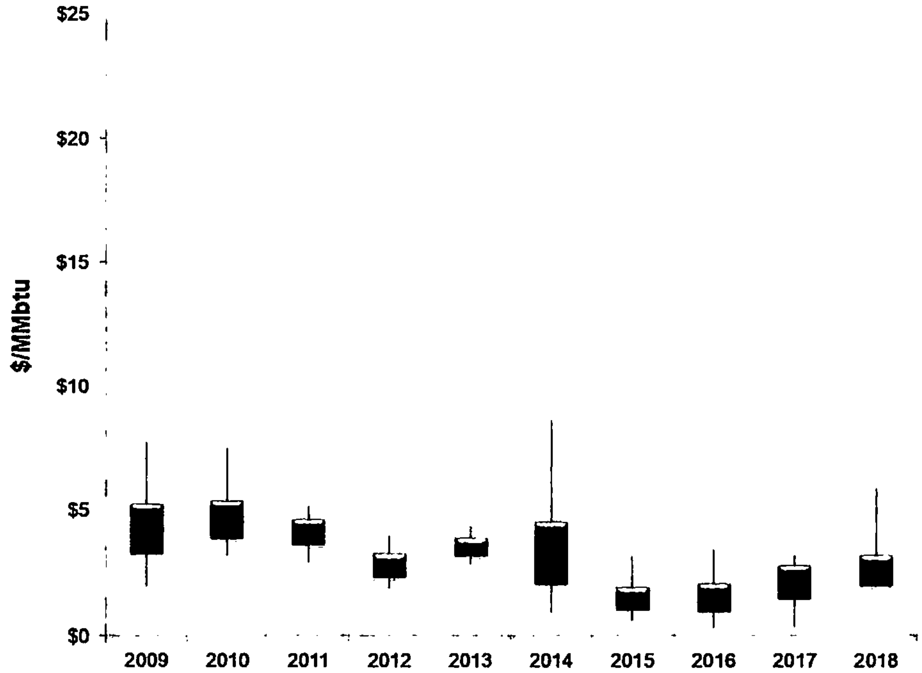
Figure 6.7.5.11 – Natural Gas Daily Average Price Ranges – South Point



Note: A larger box indicates greater price volatility than a smaller box. Prices through March 31, 2018.

On-site Liquid Natural Gas Storage

On-site liquid natural gas ("LNG") storage provides short periods of plant fueling and requires long refill times. It also serves as a backup fueling arrangement capable of mitigating risk associated with a system-wide pipeline disruption scenario, while providing an option that has operating characteristics similar to natural gas. However, this type of fueling arrangement provides limited operating cost risk mitigation. The natural gas required to fill LNG storage would be supplied using natural gas purchased at market prices with limited assurance that price would be lower during the refill process than when used as a fueling source. LNG storage capacity would generally be large enough to fuel a plant for several days, while taking several months to refill the storage.

6.8 GENERATION UNIT RETIREMENTS

Plans A through E include several generating unit retirements that were necessary to minimize overall costs to the Company's customers or to meet the CO_2 limits required by the program being assessed (i.e., Virginia RGGI, RGGI, and Federal CO_2 Program).

The generators listed below should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date. For purposes of this 2018 Plan, the assumptions regarding generation unit retirements are as follows:

- Bellemeade (267 MW) to be potentially retired by 2021 in all Alternative Plans;
- Bremo Units 3 and 4 (227 MW) to be potentially retired by 2021 in all Alternative Plans;
- Chesterfield Units 3 and 4 (261 MW) to be potentially retired by 2021 in all Alternative Plans;
- Mecklenburg Units 1 and 2 (138 MW) to be potentially retired by 2021 in all Alternative Plans;
- Pittsylvania (83 MW) to be potentially retired by 2021 in all Alternative Plans;

- Possum Point Units 3 and 4 (316 MW) to be potentially retired by 2021 in all Alternative Plans;
- Possum Point Unit 5 (786 MW) to be potentially retired by 2021 in all Alternative Plans;
- Yorktown Unit 3 (790 MW) to be potentially retired by 2022 in all Alternative Plans;
- Chesterfield Units 5 (336 MW) and 6 (670 MW) to be potentially retired by 2023 in Alternative Plans B, C, and D; and
- Clover Units 1 (220 MW) and 2 (219 MW) to be potentially retired by 2025 in Alternative Plans B, C, and D.

6.9 MISCELLANEOUS ANALYSIS

Retire/Co-Fire/Repower Analysis

This analysis was focused on the Company's coal-fired and heavy oil-fired facilities and assessed the cost to customers of the retirement, co-firing natural gas, and repowering of these facilities to exclusively burn natural gas. The analysis was performed using the PLEXOS model and assumed CO_2 limitations and market forecasts consistent with three scenarios: No CO_2 Tax, RGGI, and the Federal CO_2 Program.

The retirement analysis included an assessment of the forecasted unit economics and the cost to customers assuming: (i) continued business operations of these facilities; (ii) the potential retirement of these facilities; (iii) 25% and 100% co-firing natural gas at these facilities; and (iv) repowering these facilities to exclusively burn natural gas. In the case of retirement, this analysis considered the cost of retirement and replacement of these facilities. The co-firing and repowering analysis considered all plant capital costs associated with natural gas fueling along with all pipeline and other fuel costs associated with delivering natural gas to the facility. The co-fire and repower alternatives assumed a commercial operations date of 2020. All co-fire and repower options analyzed resulted in a higher cost compared to unaltered operations of a unit.

Units with negative or marginal value were included as retirements. Virginia coal-fired and heavy oil-fired facilities tended to have less upside potential in the long run under the RGGI scenario. The results of the analysis are included in Figure 6.9.1, as described in Section 6.8 above and shown in each Alternative Plan. A negative sign in Figure 6.9.1 indicates an adverse impact (i.e., increase) on cost to the customer by continuing to operate the unit, while a positive sign indicates a decrease in cost to the customer. No decisions have been finalized concerning these units as work continues to lower costs and verify grid stability.

Figure 6.9.1 – Retirement Analysis Results

Units	No CO_2 Tax	RGGI	Federal CO_2 Program
Chesterfield 5 - 6	+	-	+
Clover 1 - 2	+	Marginal	+
Mt. Storm 1 - 3	+	+	+
Possum Point 5	-	-	-
Yorktown 3	Marginal	-	Marginal

PJM DOM Zone Load Forecast

For the past two years, PJM's load forecast for the DOM Zone has been lower than the Company's load forecast. To show the effect of a lower load forecast on a generation expansion plan, the Company has included an additional analysis in this 2018 Plan. In this analysis, the Company used PJM's load forecast for the DOM Zone that was included in the 2018 PJM Load Forecast Report. This PJM load forecast was run in the PLEXOS model under the No CO_2 Tax scenario provided by

ICF. The optimized results were then compared against the results identified in Plan A: No CO_2 Tax. Figure 6.9.2 reflects the build plan and Figure 6.9.3 reflects the NPV of that comparison. While the Company includes this analysis, it reiterates the issues with PJM's load forecasting methodology discussed in Section 2.3.

Figure 6.9.2 – PJM Low Load Build Plan

Year	Plan A: No CO_2 Tax	No CO_2 Tax (PJM Low Load)
Approved DSM: 304 MW, 805 GWh by 2033		
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)
2025	CT SLR (400 MW)	SLR (320 MW)
2026	CT SLR (480 MW)	SLR (480 MW)
2027	CT SLR (480 MW)	
2028	SLR (480 MW)	CT
2029		SLR (80 MW)
2030	CT	CT
2031	CT SLR (160 MW)	SLR (80MW)
2032	CT SLR (240 MW)	CT
2033	SLR (80 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CH: Chesterfield Power Station; CT: Combustion Turbine (2 units); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.
2) These units entered into cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These units are planned to enter cold reserve in December 2018.

Figure 6.9.3 – Low Load NPV Comparison

	No CO_2 Tax (PJM Low Load)
NPV Compliance Cost ($B)	$ (3.35)

6.10 2018 PLAN

As discussed in Chapter 1, the uncertainty with respect to the timing and form of CO_2 regulation at the federal level remains high. Although Virginia is actively pursuing regulations and has proposed a state program linked to RGGI, a final regulation is not expected until later this year. Until the rules that will be applicable to Virginia are certain, it is difficult to recommend a specific long-term plan. Therefore, as mentioned in Chapter 1, the 2018 Plan offers no "Preferred Plan" and no recommended long-term path forward other than the guidance offered in the STAP discussed in Chapter 7.

Rather, this 2018 Plan offers the Alternative Plans for consideration, each of which may be a likely path forward once the uncertainty of GHG regulation is resolved. Plan A offers a path forward should no CO_2 regulations be adopted of any kind. Plans B through E each identify plans that are compliant with a possible form of RGGI or a Federal CO_2 Program that, based on ICF's view, may occur in the future. Collectively, this analysis and presentation of the Alternative Plans, along with the decision to pursue the STAP, comprises the 2018 Plan.

CHAPTER 7 – SHORT-TERM ACTION PLAN

The STAP provides the Company's strategic plan for the next five years (2019 to 2023), as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in this 2018 Plan. The Company continues to proactively position itself in the short-term to address the evolving developments surrounding future CO_2 emission mitigation rules or regulations, or societal and customer preferences for the benefit of all stakeholders over the long term. Over the next five years, the Company expects to:

- Continue development of planning processes that will reasonably assess the actions and costs associated with the integration of large volumes of intermittent renewable generation on the transmission and distribution networks;
- Enhance and upgrade the Company's existing transmission and distribution grid;
- Enhance the Company's access to natural gas supplies, including shale gas supplies from multiple supply basins;
- Construct additional generation while maintaining a balanced fuel mix;
- Continue to lower the Company's emissions footprint;
- Continue to develop and implement a renewable strategy that supports the Virginia RPS goals and the North Carolina REPS requirements;
- Implement cost-effective programs based on measures identified in the 2017 DSM Potential Study and continue to implement cost-effective DSM programs in Virginia and North Carolina (DSM provisions of the GTSA will be reflected in future plans after the completion of the stakeholder process required in the Act);
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements;
- Enhance reliability and customer service;
- Continue development of the CVOW facility; and
- Continue analysis and evaluations for the 20-year nuclear license extensions for Surry Units 1 and 2, and North Anna Units 1 and 2.

7.1 DIFFERENCES IN THE STAP FROM THE 2017 PLAN TO THE 2018 PLAN

Figure 7.1.1 displays the differences between the 2017 STAP and the 2018 STAP.

Figure 7.1.1 - Changes between the 2017 and 2018 Short-Term Action Plans

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Cold Storage	Retire	
2018		SLR NUG		Belle[2], Bremo 3&4[2], CH 3&4[4], MB 1&2[2], Pitt[3], PP 3&4[4]	YT 1&2[5]	Approved DSM
2019	Greensville	SLR NUG[6]	~~PP5 – SNCR~~			
2020		US-3 Solar 1 SLR				
2021		US-3 Solar 2 SLR CVOW[7]			Belle, Bremo 3&4 CH 3&4, MB 1&2, Pitt PP 3-5	
2022	CT	SLR			~~CH 3&4~~, YT3	
2023	CT	SLR				

Key: Retrofit: Additional environmental control reduction equipment; Retire: Remove a unit from service; Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CH: Chesterfield Power Station; US-3 Solar 1: US-3 Solar 1 Facility; CVOW: Coastal Virginia Offshore Wind Project; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SNCR: Selective Non-Catalytic Reduction; SLR NUG: Solar NUG; SLR: Generic Solar: US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Color Key: Blue: Updated resource since 2017 Plan; Red with Strike: 2017 Plan resource replacement; Black: No change from 2017 Plan.

Note: 1) DSM capacity savings increases throughout the Planning Period.

2) These generating units entered cold reserve in April 2018.

3) Pittsylvania is planned to enter cold reserve in August 2018.

4) These generating units are planned to enter cold reserve in December 2018.

5) Yorktown Units 1 and 2 ceased operations on April 15, 2017 to comply with the MATS rule. They are now available for emergency operation per PJM.

6) Solar NUG capacity changed to 760 MW total in VA and NC.

7) 12 MW (nameplate) CVOW was previously referred to as VOWTAP in the 2017 Plan.

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

7.2 GENERATION RESOURCES

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

- Place the Greensville County Power Station (1,585 MW), approved on March 29, 2016, into service by 2019;
- Continue technical evaluations and aging management programs required to support a second license extension of the Company's existing Surry Units 1 and 2 and North Anna Units 1 and 2; and
- Submit an application for the second renewed operating licenses for Surry Units 1 and 2 by the end of the first quarter of 2019 and for North Anna Units 1 and 2 by the end of 2020.

Figure 7.2.1 lists the generation plants that are currently under construction and are expected to be operational by 2023. Figure 7.2.2 lists the generation plants that are currently under development and are expected to be operational by 2023 subject to SCC approval.

Figure 7.2.1 - Generation under Construction

Forecasted COD[1]	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW)		
					Nameplate	Summer	Winter
2019	Greensville County Power Station	VA	Natural Gas	Intermediate/Baseload	1,585	1,585	1,710

Note: 1) Commercial Operation Date.

Figure 7.2.2 - Generation under Development[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Summer Capacity (Net MW)	Winter Capacity (Net MW)
2020	US-3 Solar 1	VA	Solar	Intermittent	142	33	33
2021	US-3 Solar 2	VA	Solar	Intermittent	98	22	22
2021	CVOW	VA	Wind	Intermittent	12	2	2
Ongoing	Surry Unit 1 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
Ongoing	Surry Unit 2 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
Ongoing	North Anna Unit1 Nuclear Extension	VA	Nuclear	Baseload	838	838	868
Ongoing	North Anna Unit 2 Nuclear Extension	VA	Nuclear	Baseload	834	834	863

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

7.3 RENEWABLE ENERGY RESOURCES

Approximately 533 MW of qualifying renewable generation is currently in operation. Over the next five years, the Company expects to take the following actions regarding renewable energy resources:

Virginia

- Achieve 61 MW of biomass capacity at VCHEC by 2023;
- Meet its targets under the Virginia RPS Program by applying renewable generation from existing qualified facilities and purchasing cost-effective RECs;
- Submit its Annual Report to the SCC detailing its efforts towards the RPS plan;
- Apply for SCC approval of US-3 Solar 1 and US-3 Solar 2 Facilities in 2018;
- Continue development of CVOW; and
- Continue development of solar PV resources consistent with the generic solar facilities included in Figure 7.3.1.

North Carolina

- Submit its 2018 REPS Compliance Report for compliance year 2017 in August 2018;
- Submit its annual REPS Compliance Plan (filed as North Carolina Plan Addendum 1 to this 2018 Plan); and
- Enter into or negotiate PPAs with approximately 660 MW (nameplate) of North Carolina solar NUGs by 2020.

Figure 7.3.1 lists the Company's renewable resources included in all Alternative Plans for the next five years.

Figure 7.3.1 - Renewable Resources by 2023

Resource	Nameplate MW
Existing Resources[1]	533
VCHEC Biomass	61
Solar NUGs[2]	760
CVOW	12
US-3 Solar 1	142
US-3 Solar 2	98
Solar 2020	320
Solar 2021	400
Solar 2022	480
Solar 2023	480

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2020.

7.4 TRANSMISSION

Virginia

The following planned Virginia transmission projects detailed in Figure 7.4.1 are pending SCC approval or are tentatively planned for filing with the SCC:

- Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230kV Lines and New 230kV Substation;
- Line #217 Chesterfield to Lakeside Rebuild;
- Line #549 Dooms to Valley Rebuild;
- Line #112 Fudge Hollow to Lowmoor Partial Rebuild;
- Line #231 Landstown to Thrasher Rebuild;
- Line #211 and Line #228 Chesterfield to Hopewell Partial Rebuild;
- Line #550 Mount Storm to Valley Rebuild;
- Line #2189 Glebe to Potomac River – New 230 kV Line;
- Line #2175 Idylwood to Tysons – New 230 kV Line and New 230 kV Tysons Substation;
- Line #205 and Line #2003 Chesterfield to Tyler Partial Rebuild; and
- Line #247 Suffolk to Swamp Rebuild.

Figure 7.4.1 lists the major transmission additions including line voltage, capacity, and expected operation target dates.

Figure 7.4.1 - Planned Transmission Additions

Line Terminals	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #47 Kings Dominion to Fredericksburg Rebuild	115	353	May-18	VA
Line #4 Bremo to Cartersville Uprate	115	151	May-18	VA
Line #2183 Brambleton to Poland Road – New 230 kV Line and New 230 kV Substation	230	1,047	May-18	VA
Line #2174 Vint Hill to Wheeler – New 230 kV Line	230	1,047	Jun-18	VA
Line #553 Cunningham to Elmont Rebuild	500	4,330	Jun-18	VA
Line #1009 Ridge Road to Chase City Rebuild	115	346	Jun-18	VA
Line #1020 Pantego to Trowbridge – New 115 kV Line	115	346	Jun-18	NC
Line #1015 Scotland Neck to South Justice Branch – New 115 kV Line	115	346	Sep-18	NC
Line #2086 Remington Combustion Turbine to Warrenton Rebuild	230	1,047	Oct-18	VA
Line #48 Sewells Point to Thole Street and Line #107 Oakwood to Sewells Point Partial Rebuild	115	317 (#48) 353 (#107)	Dec-18	VA
Line #585 Carsons to Rogers Road Rebuild	500	4,330	Dec-18	VA
Line #54 Carolina to Woodland Reconductor	115	174	Dec-18	NC
Line #2161 Wheeler to Gainesville Uprate	230	1,047	Dec-18	VA
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild	115	353 (#34)	May-19	VA
Line #582 Surry to Skiffes Creek – New 500 kV Line	500	4,330	May-19	VA
Line #159 Acca to Hermitage Reconductor	115	353	May-19	VA
Line #2138 Skiffes Creek to Whealton – New 230 kV Line	230	1,047	May-19	VA
Line #171 Chase City to Boydton Plank Road Rebuild	115	393	Jun-19	VA
Line #534 Cunningham to Dooms Rebuild	500	4,330	Jun-19	VA
Line #82 Everetts to Leggetts Crossroads Delivery Point Rebuild	115	353	Dec-19	NC
Line #166 and Line #67 Greenwich to Burton Rebuild	115	353	Dec-19	VA
Line #90 Carolina to Kerr Dam Rebuild	115	346	Dec-19	VA/NC
Line #130 Clubhouse to Carolina Rebuild	115	394	Dec-19	VA/NC
Line #65 Norris Bridge Rebuild	115	147	Dec-19	VA
Line #18 Possum Point to Smoketown and Line #145 Smoketown to Possum Point Rebuild	115	524	Dec-19	VA
Line #547 Bath County to Lexington Series Capacitor Upgrade	500	3,397	Apr-20	VA
Line #548 Bath County to Valley Series Capacitor Upgrade	500	3,397	Apr-20	VA
Line #2153 Remington to Gordonsville – New 230 kV Line	230	1,047	Jun-20	VA
Line #217 Chesterfield to Lakeside Rebuild	230	1,047	Jun-20	VA
Line #549 Dooms to Valley Rebuild	500	4,330	Jun-20	VA
Line #112 Fudge Hollow to Lowmoor Partial Rebuild	138	314	Oct-20	VA
Line #154 Twittys Creek to Pamplin Rebuild	115	353	Dec-20	VA
Line #76 and Line #79 Yorktown to Peninsula Rebuild	115	346	Dec-20	VA
Line #231 Landstown to Thrasher Rebuild	230	1,046	Dec-20	VA
Line #211 and Line #228 Chesterfield to Hopewell Partial Rebuild	230	477	Dec-20	VA
Line #550 Mount Storm to Valley Rebuild	500	4,330	Jun-21	VA
Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230 kV Lines and New 230 kV Substation	230	1,047	Jul-21	VA
Line #127 Buggs Island to Plywood Rebuild	115	353	Dec-21	VA
Line #120 Dozier to Thompsons Corner Partial Rebuild	115	346	Dec-21	VA
Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Rebuild	115	353	Dec-21	VA
Line #2175 Idylwood to Tysons – New 230 kV Line and Tysons Substation Rebuild	230	1,047	Jun-22	VA
Line #2001 Possum Point to Occoquan Reconductor and Uprate	230	1,047	Jun-22	VA
Line #227 Beaumeade to Brambleton – Cut-in Belmont Substation	230	1,057	Jun-22	VA
Line #29 Fredericksburg to Possum Point Partial Rebuild	115	361	Dec-22	VA
Line #205 and Line #2003 Chesterfield to Tyler Partial Rebuild	230	1,047	Dec-22	VA
Line #247 Suffolk to Swamp Rebuild	230	1,047	Dec-22	VA/NC
Line #2144 Winfall to Swamp Rebuild	230	1,047	Dec-22	NC
Line #101 Mackeys to Creswell Rebuild	115	262	Dec-22	NC
Line #43 Staunton to Harrisonburg Rebuild	115	262	Dec-22	VA
Line #2189 Glebe to Potomac River – New 230 kV Line	230	900	2022	VA

7.5 DEMAND-SIDE MANAGEMENT

The Company continues to evaluate the measures identified in the 2017 DSM Potential Study and may include additional measures in DSM programs in future Plans. The measures included in the 2017 DSM Potential Study still need to be part of a program design effort that looks at the viability of the potential measures as a single or multi-measure DSM program. These fully-designed DSM programs would also need to be evaluated for cost effectiveness. Under the GTSA, which will become law on July 1, 2018, the Company will propose energy efficiency programs with projected costs of at least $870 million for the period beginning July 1, 2018, and ending July 1, 2028, including its existing approved energy efficiency programs. This legislation included requirements for a new stakeholder process, as discussed further in Section 7.6. The Company will work through that process to develop future programs for filing.

Virginia

The Company will continue its analysis of future programs and may file for approval of new or revised programs that meet the Company requirements for new DSM resources. The Company filed its "Phase VII" DSM Application in October 2017, seeking approval of an extension of the Phase IV Residential Income and Age Qualifying Home Improvement Program (Case No. PUR-2017-00129). The SCC is expected to issue its Final Order in this case by June 2018.

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 the Company requirements for new DSM resources. On July 28, 2017, the Company filed in Docket No. E-22, Sub 543 for NCUC approval of the Non-Residential Prescriptive Program that was approved in Virginia in Case No. PUE-2016-00111. On October 16, 2017, the NCUC approved this new DSM program, which has been available to qualifying North Carolina customers since January 2018.

Figure 7.5.1 lists the projected demand and energy savings by 2023 from the approved DSM programs.

Figure 7.5.1 - DSM Projected Savings By 2023

Program	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Air Conditioner Cycling Program	91	-	Approved / Approved
Residential Low Income Program	2	10	Completed / Completed
Residential Lighting Program	-	-	
Commercial Lighting Program	-	1	Closed / Closed
Commercial HVAC Upgrade	1	6	
Non-Residential Distributed Generation Program	11	-	Extension Approved / Rejected
Non-Residential Energy Audit Program	-	2	Completed / Completed
Non-Residential Duct Testing and Sealing Program	11	68	
Residential Bundle Program	11	52	
Residential Home Energy Check-Up Program	6	34	
Residential Duct Sealing Program	-	1	
Residential Heat Pump Tune Up Program	-	-	
Residential Heat Pump Upgrade Program	5	17	Extension Rejected / Completed
Non-Residential Window Film Program	42	46	Approved / Approved
Non-Residential Lighting Systems & Controls Program	34	213	
Non-Residential Heating and Cooling Efficiency Program	47	127	
Income and Age Qualifying Home Improvement Program	3	14	Extension Under Consideration / Suspended
Residential Appliance Recycling Program	1	10	Completed
Small Business Improvement Program	17	64	Approved / Approved
Residential Retail LED Lighting Program (NC only)	1	7	No Plans / Approved
Non-Residential Prescriptive Program	32	217	Approved / Approved

7.6 GTSA COMPLIANCE

In the 2017 Plan Final Order, the SCC directed the Company to include in future filings "detailed plans to implement the mandates contained in [the GTSA]." Figure 7.6.1 provides a list of "mandates" and the accompanying citation to the GTSA. The sections that follow outline these mandates and detail the Company's plans related to each one over the five-year STAP period. It should be noted that several provisions of the GTSA encourage specific public policies, such as greater deployment of renewable energy, without taking the form of a mandate.

Figure 7.6.1 – 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	EC 15
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	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	EC 15

Plan-Related Mandates

The GTSA amends Va. Code § 56-599 to require the Company to evaluate electric grid transformation projects and energy efficiency measures. While these new provisions do not take effect until July 1, 2018, the Company discusses its plans related to these provisions below.

The GTSA also requires the Company to include specific analysis in its future Plans. Specifically, Enactment Clause ("EC") 18 requires certain analysis related to energy efficiency measures, and EC 12 requires consideration of combined heat and power or waste heat to power measures or generation alternatives. The Company plans to include this required analysis in its next Plan.

Rate-Related Mandates

The GTSA contains a number of mandates related to customer rates. First, the Company must reduce its rates for generation and distribution services to reflect the reduction in corporate income taxes under the federal Tax Cuts and Jobs Act of 2017 (the "TCJA"). As set forth in EC 7 of the GTSA, the Company plans to "reduce its existing rates for generation and distribution services on an interim basis, within 30 days of July 1, 2018, in an amount sufficient to reduce its annual revenues from such rates by an aggregate amount of $125 million." The Company will then provide the SCC with the necessary information to "true-up . . . this interim reduction amount to the actual annual reduction in corporate tax obligations of [the Company] as of the effective date of the [TCJA]," as set forth in EC 6. In carrying out these mandates, the Company will comply with the SCC's April 16, 2018 Order in Case No. PUR-2018-00055.

Second, the Company must issue one-time, voluntary generation and distribution services bill credits. As set forth in EC 4 of the GTSA, the Company plans to "no later than 30 days following July 1, 2018, . . . provide to its current customers a one-time, voluntary generation and distribution services bill credit, to be allocated on a historic test period energy usage basis, in an aggregate amount of $133 million." Then, as set forth in EC 5, the Company plans to "no later than 30 days after January 1, 2019, . . . provide to its current customers a one-time, voluntary generation and distribution services bill credit, to be allocated on a historic test period energy usage basis, in an aggregate amount of $67 million." In carrying out these madates, the Company will comply with the SCC's April 16, 2018 Order in Case No. PUR-2018-00053.

Next, the GTSA requires the Company to provide the Manufacturing and Commercial Competitiveness Retention Credit to eligible customers. The Company plans to offer this credit to eligible customers.

Finally, the GTSA outlines the structure through which Company rates will be set going forward. The Company plans to make a triennial review filing by March 31, 2021.

Mandated Reports

The GTSA next includes a list of reports that the Company must file with the SCC and others. Figure 7.6.2 provides a list of required reports. The Company plans to file these mandated reports by the statutory deadline.

Figure 7.6.2 – GTSA Mandated Reports

Report	Deadline	Citation
Report on potential improvements to renewable programs	November 1, 2018	EC 17
Report on economic development activities	December 1, 2018	EC 16
Report on the feasibility of providing broadband using utility infrastructure	December 1, 2018	EC 13
Report on energy efficiency programs	July 1, 2019 (then annually)	EC 15

Pilot Program Mandates

The GTSA contains 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 plans to continue this pilot program and will develop a plan to meet the required funding.

Second, the GTSA requires the SCC to establish a pilot program for storage batteries. The GTSA mandates that the Company submit a proposal to deploy up to 30 MW of batteries. The Company plans to submit a proposal compliant with the GTSA and with the rules and guidelines to be established by the SCC.

Mandate Related to Electric Distribution Grid Transformation Projects

EC 15 of the GTSA mandates that the Company "petition the SCC, not more than once annually, for approval of a plan for electric distribution grid transformation projects." The GTSA defines "electric distribution grid transformation projects" as follows:

> "Electric distribution grid transformation project" means a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information.

The Company plans to file a grid transformation plan by the end of 2018.

Mandate Related to Energy Conservation Measures

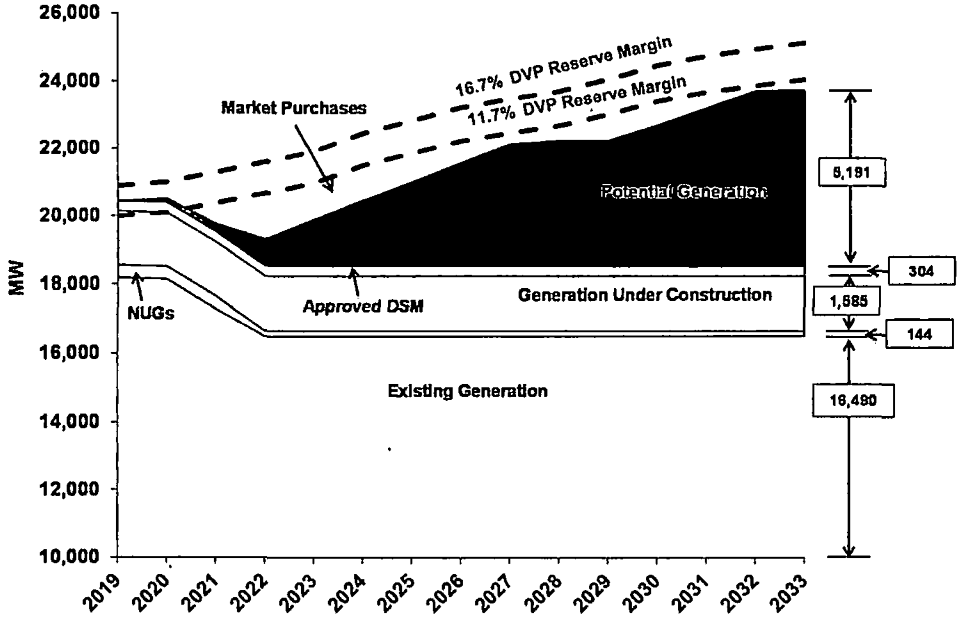
EC 15 of the GTSA directs the Company to develop a proposed program of energy conservation measures with a projected cost of no less than $870 million for the period beginning July 1, 2018, and ending July 1, 2028. At least five percent of the proposed programs must benefit low-income, elderly, and disabled individuals. The program must provide for the submission of "petitions for approval to design, implement, and operate energy efficiency programs" under Va. Code § 56-585.1 A 5 c. In developing these programs, the Company must utilize a stakeholder process to receive input and feedback on the development of its energy efficiency programs. The stakeholder process will be facilitated by an independent monitor compensated under the funding provided pursuant to Va. Code § 56-592.1 E, and will include representatives from the SCC, the Attorney General's Office of Consumer Counsel, the Department of Mines, Minerals and Energy, energy efficiency program implementers, energy efficiency providers, residential and small business customers, and any other interested stakeholder who the independent monitor deems appropriate for inclusion. As noted above, the Company must submit an annual report on the status of these programs beginning July 1, 2019.

See Section 5.5 and 7.4 for more details on the Company's current plans for future DSM initiatives. Going forward, the Company plans to develop a proposed program of energy conservation measures as directed by the GTSA using its current plans and past experiences with its DSM programs. The Company plans to utilize the stakeholder process, once established pursuant to Va. Code § 56-592.1 E, to develop its energy efficiency programs as required.

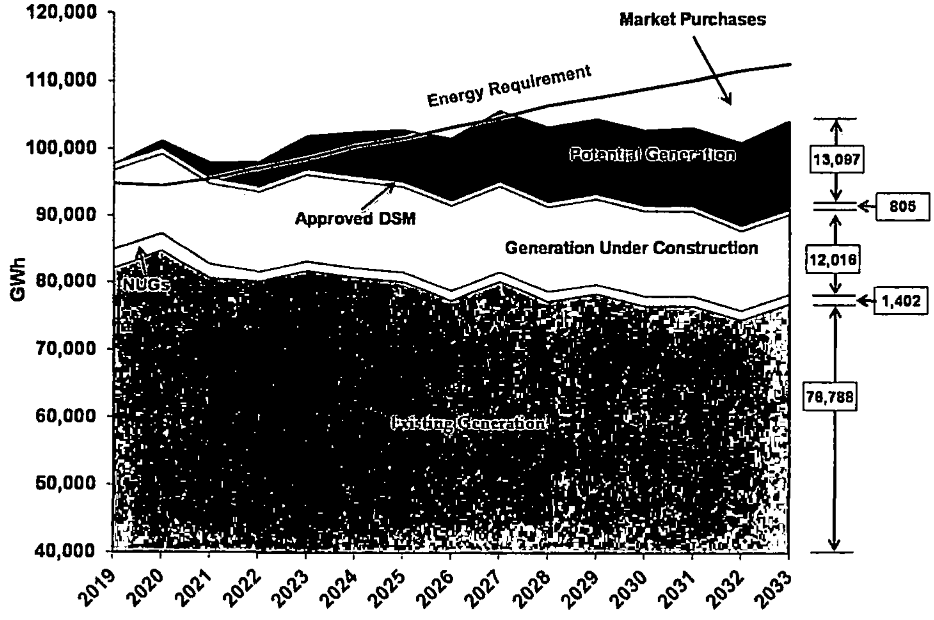
APPENDIX

Appendix 1A – Plan A: No CO_2 Tax – Capacity & Energy

Capacity



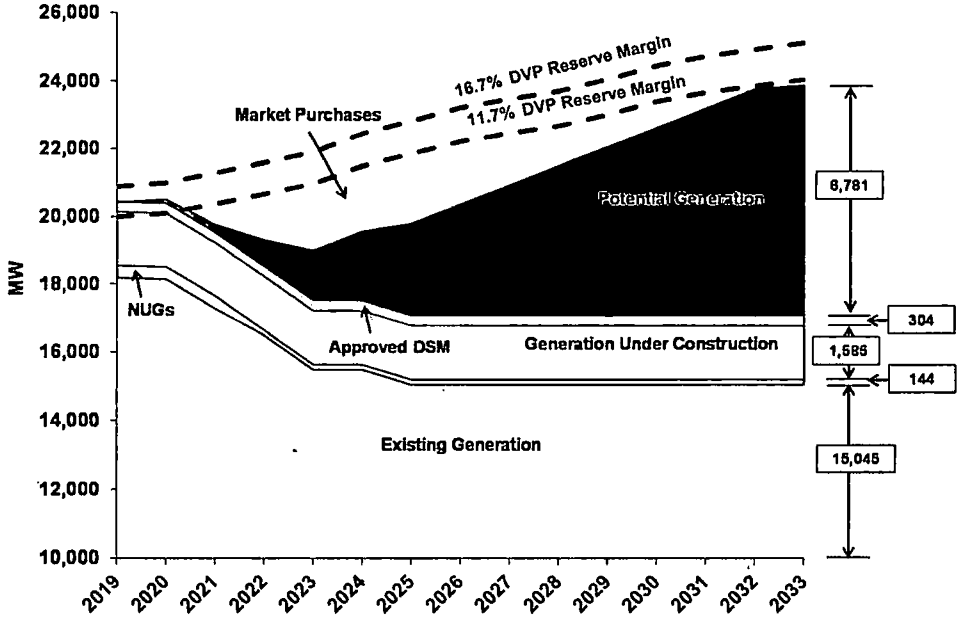
Energy



Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan B: Virginia RGGI (unlimited imports) – Capacity & Energy

Capacity



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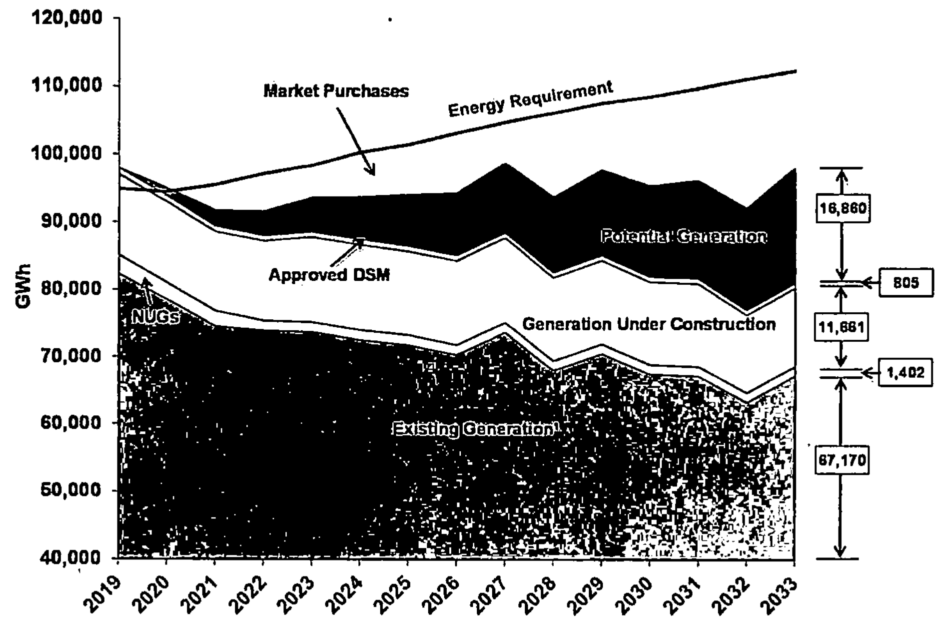
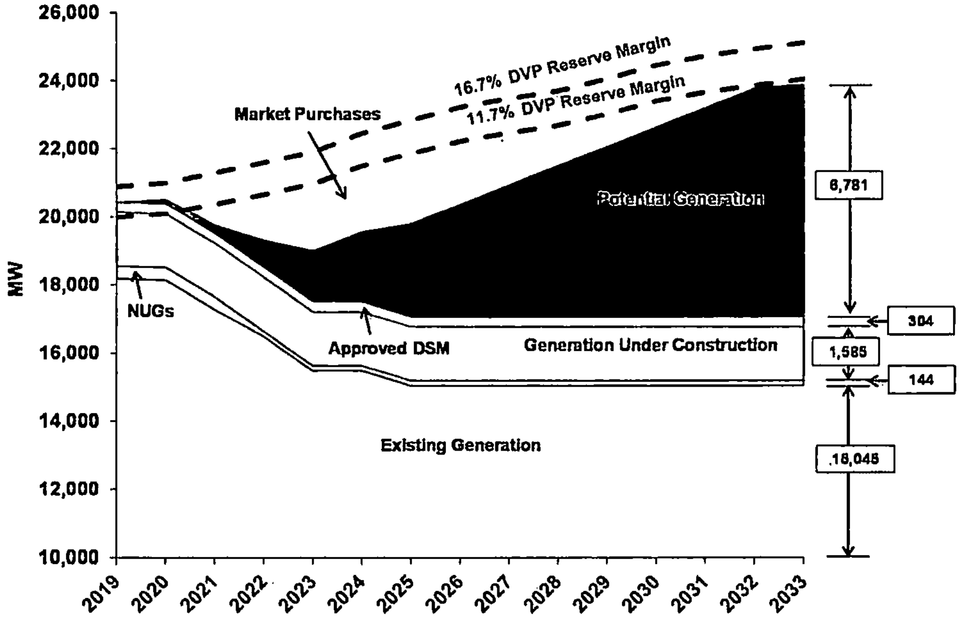


Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan C: RGGI (unlimited imports) – Capacity & Energy

Capacity



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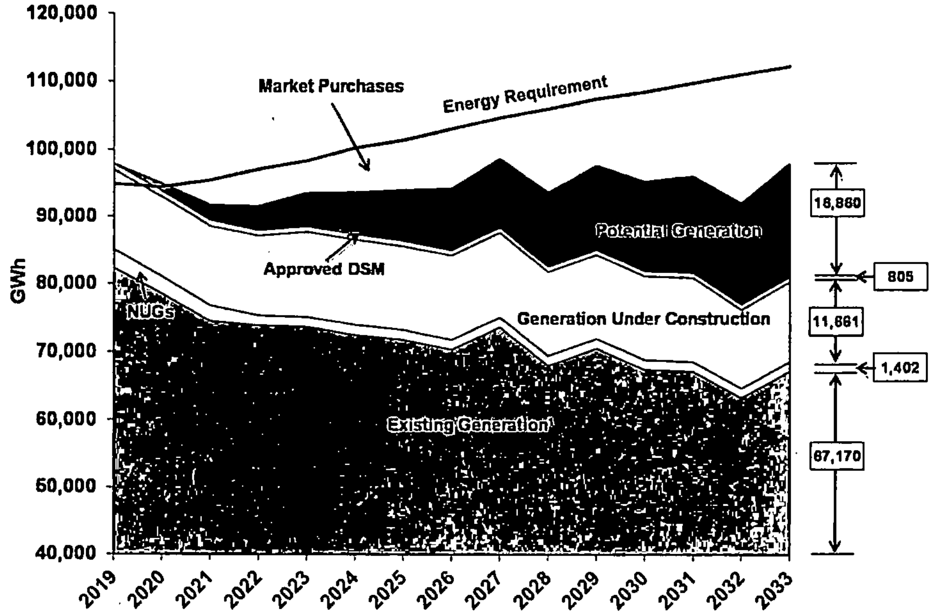

Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

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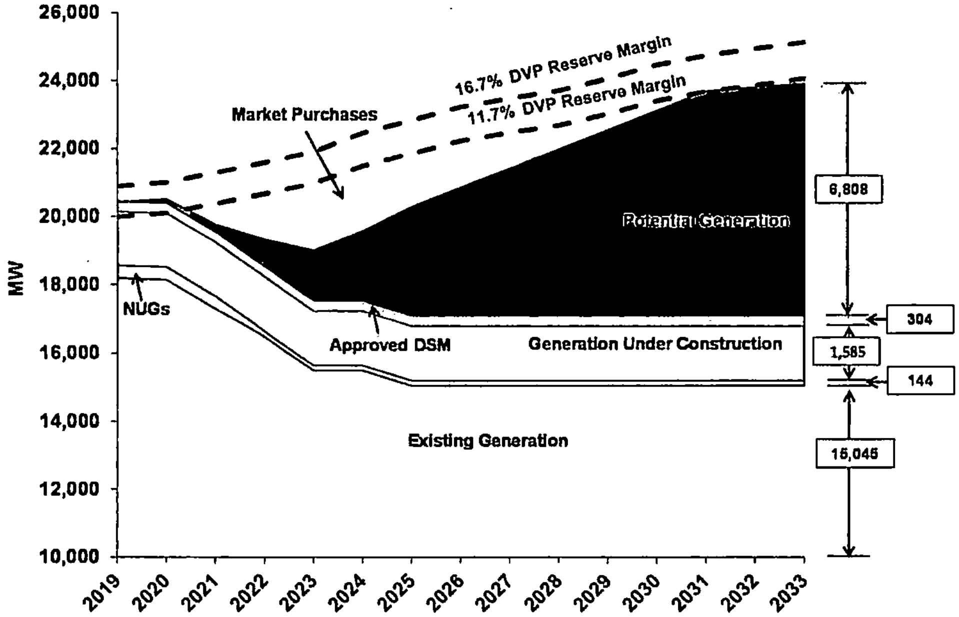
Appendix 1A – Plan D: RGGI (limited imports) – Capacity & Energy

Capacity



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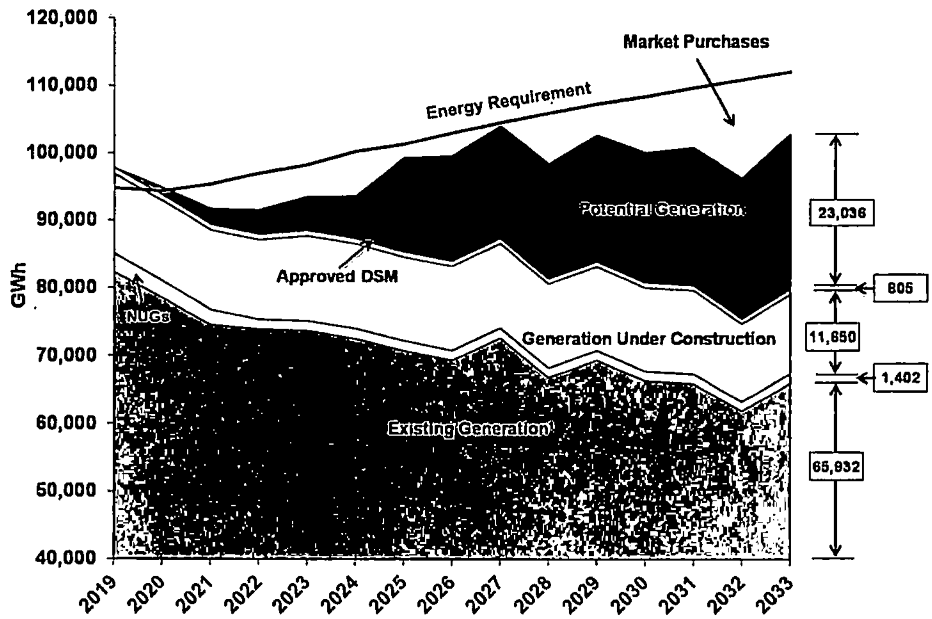
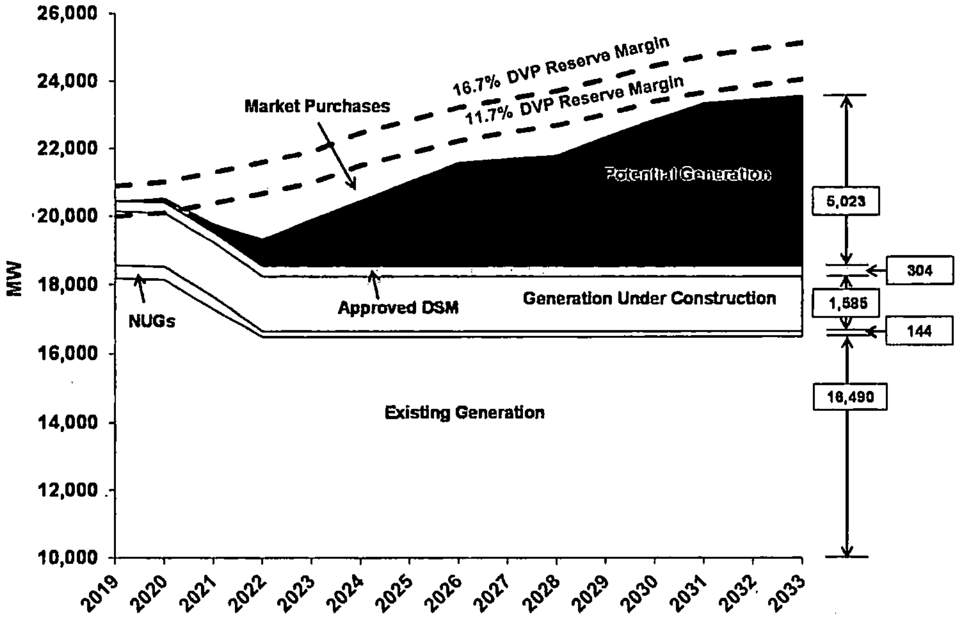


Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan E: Federal CO_2 Program – Capacity & Energy

Capacity



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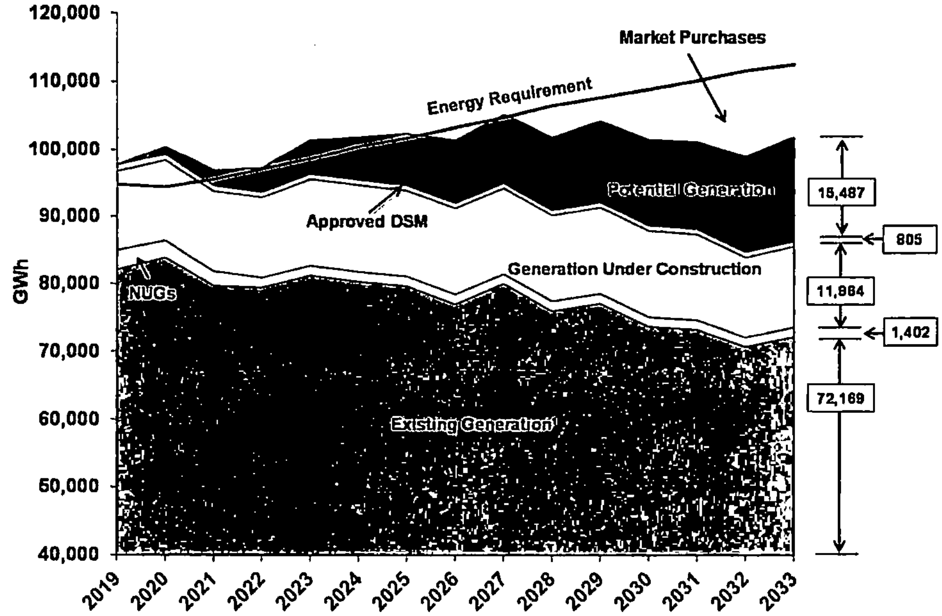

Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1B – CPP Scenario

As stated earlier in this 2018 Plan, the Company no longer believes the CPP to be a "current" or "pending" regulation. As such, the Company has not included a CPP scenario as part of the Alternative Plans. The Company has included, however, a single CPP assessment. In this case, the Company determined the optimized generation expansion plan should the U.S. adopt CO_2 regulations consistent with the CPP. This evaluation assumed a mass-based program for Virginia that regulated existing and new generation as that term is defined in the CPP.

The figures below reflect the build plan and NPV of the CPP scenario as compared to Plan A: No CO_2 Tax.

Year	Plan A: No CO_2 Tax	CPP Scenario
Approved DSM: 304 MW, 805 GWh by 2033		
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)
2025	CT SLR (400 MW)	CT SLR (400 MW)
2026	CT SLR (480 MW)	CT SLR (480 MW)
2027	CT SLR (480 MW)	CT SLR (480 MW)
2028	SLR (480 MW)	CT SLR (480 MW)
2029		SLR (480 MW)
2030	CT	CT SLR (480 MW)
2031	CT SLR (160 MW)	SLR (480 MW)
2032	CT SLR (240 MW)	CT
2033	SLR (80 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CH: Chesterfield Power Station; CT: Combustion Turbine (2 units); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility;YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.
2) These units entered into cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These units are planned to enter cold reserve in December 2018.

	CPP Scenario	
NPV Compliance Cost ($B)	$	0.85

Appendix 2A – Total Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	29,646	28,484	9,779	10,529	282	1,990	80,710
2009	29,904	28,455	8,644	10,448	276	1,932	79,658
2010	32,547	29,233	8,512	10,670	281	1,921	83,164
2011	30,779	28,957	7,960	10,555	273	2,011	80,536
2012	29,174	28,927	7,849	10,496	277	1,984	78,709
2013	30,184	29,372	8,097	10,261	276	1,956	80,145
2014	31,290	29,964	8,812	10,402	261	1,981	82,710
2015	30,923	30,282	8,765	10,159	275	1,856	82,260
2016	28,213	31,366	8,715	10,161	253	1,609	80,318
2017	29,737	32,292	8,638	10,555	258	1,607	83,086
2018	30,245	32,166	8,700	10,443	284	1,601	83,439
2019	30,743	32,714	8,814	10,575	286	1,618	84,750
2020	31,071	33,532	8,757	10,628	288	1,644	85,919
2021	31,305	34,663	8,605	10,777	289	1,659	87,299
2022	31,541	35,861	8,439	10,887	291	1,675	88,694
2023	31,844	36,983	8,289	11,069	293	1,692	90,169
2024	32,291	38,137	8,218	11,201	294	1,715	91,856
2025	32,539	39,131	8,192	11,234	296	1,727	93,120
2026	32,874	40,194	8,201	11,367	297	1,745	94,678
2027	33,211	41,190	8,213	11,470	299	1,764	96,146
2028	33,695	42,200	8,245	11,615	300	1,791	97,846
2029	34,007	42,920	8,211	11,789	302	1,811	99,040
2030	34,399	43,653	8,204	11,965	303	1,835	100,358
2031	35,032	44,410	8,190	11,936	304	1,857	101,728
2032	35,363	45,409	8,263	12,184	305	1,880	103,406
2033	35,649	45,967	8,269	12,175	307	1,903	104,270

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2B– Virginia Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	28,100	27,679	8,064	10,391	273	1,901	76,408
2009	28,325	27,646	7,147	10,312	268	1,883	75,581
2010	30,831	28,408	6,872	10,529	273	1,870	78,784
2011	29,153	28,163	6,342	10,423	265	1,958	76,304
2012	27,672	28,063	6,235	10,370	269	1,934	74,544
2013	28,618	28,487	6,393	10,134	267	1,906	75,804
2014	29,645	29,130	6,954	10,272	253	1,930	78,184
2015	29,293	29,432	7,006	10,029	266	1,803	77,829
2016	26,652	30,537	6,947	10,033	245	1,556	75,971
2017	28,194	31,471	6,893	10,429	250	1,555	78,792
2018	28,609	31,312	6,937	10,316	276	1,548	78,998
2019	29,098	31,856	7,052	10,448	278	1,563	80,296
2020	29,415	32,669	6,995	10,503	280	1,589	81,451
2021	29,640	33,796	6,844	10,652	281	1,604	82,817
2022	29,866	34,989	6,678	10,764	283	1,619	84,199
2023	30,159	36,106	6,528	10,946	284	1,635	85,659
2024	30,568	37,174	6,534	11,070	286	1,658	87,290
2025	30,803	38,143	6,514	11,104	287	1,669	88,520
2026	31,120	39,179	6,521	11,235	289	1,686	90,029
2027	31,439	40,149	6,530	11,337	290	1,705	91,450
2028	31,897	41,135	6,555	11,480	291	1,731	93,089
2029	32,193	41,836	6,528	11,652	293	1,750	94,252
2030	32,564	42,550	6,523	11,826	294	1,773	95,530
2031	33,162	43,288	6,512	11,797	295	1,794	96,849
2032	33,476	44,262	6,570	12,043	297	1,817	98,465
2033	33,747	44,806	6,575	12,033	298	1,839	99,298

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2C – North Carolina Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	1,546	806	1,715	138	8	88	4,302
2009	1,579	809	1,497	136	8	49	4,078
2010	1,716	825	1,640	141	8	51	4,380
2011	1,626	795	1,618	132	8	53	4,232
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	51	4,526
2015	1,630	850	1,759	130	8	53	4,430
2016	1,562	829	1,768	128	8	53	4,347
2017	1,542	821	1,744	126	8	52	4,293
2018	1,635	854	1,763	127	8	54	4,441
2019	1,645	858	1,762	126	8	54	4,454
2020	1,655	863	1,762	125	8	55	4,468
2021	1,665	867	1,761	124	8	55	4,482
2022	1,676	872	1,761	123	8	56	4,496
2023	1,686	877	1,760	122	8	57	4,510
2024	1,723	963	1,684	130	9	57	4,566
2025	1,736	988	1,679	131	9	58	4,600
2026	1,754	1,015	1,680	132	9	58	4,649
2027	1,772	1,040	1,683	133	9	59	4,696
2028	1,798	1,066	1,689	135	9	60	4,757
2029	1,814	1,084	1,682	137	9	61	4,787
2030	1,835	1,102	1,681	139	9	61	4,828
2031	1,869	1,122	1,678	139	9	62	4,879
2032	1,887	1,147	1,693	142	9	63	4,940
2033	1,902	1,161	1,694	142	9	64	4,972

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2D – Total Customer Count
(DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	2,124,089	230,715	598	29,008	2,513	5	2,386,927
2009	2,139,604	232,148	581	29,073	2,687	5	2,404,099
2010	2,157,581	232,988	561	29,041	2,798	5	2,422,974
2011	2,171,795	233,760	535	29,104	3,031	4	2,438,228
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	2,328,926	244,229	645	28,874	4,334	3	2,607,011
2019	2,359,240	246,742	644	28,999	4,478	3	2,640,106
2020	2,387,645	249,140	643	29,111	4,622	3	2,671,165
2021	2,414,477	251,434	642	29,206	4,766	3	2,700,528
2022	2,441,710	253,749	641	29,288	4,910	3	2,730,301
2023	2,469,705	256,114	640	29,366	5,054	3	2,760,882
2024	2,497,455	258,466	639	29,438	5,198	3	2,791,198
2025	2,524,076	260,749	638	29,501	5,342	3	2,820,310
2026	2,549,318	262,946	637	29,556	5,486	3	2,847,947
2027	2,573,458	265,074	636	29,603	5,630	3	2,874,405
2028	2,596,881	267,155	635	29,644	5,774	3	2,900,093
2029	2,619,731	269,201	634	29,680	5,918	3	2,925,167
2030	2,642,166	271,220	633	29,711	6,062	3	2,949,795
2031	2,664,350	273,224	632	29,738	6,206	3	2,974,153
2032	2,686,064	275,199	631	29,763	6,350	3	2,998,010
2033	2,708,306	277,201	630	29,781	6,494	3	3,022,415

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2E – Virginia Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	2,023,592	215,212	538	27,141	2,116	3	2,268,602
2009	2,038,843	216,663	522	27,206	2,290	3	2,285,526
2010	2,056,576	217,531	504	27,185	2,404	3	2,304,203
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	2,226,232	228,562	585	27,012	3,940	2	2,486,332
2019	2,256,190	231,039	584	27,140	4,083	2	2,519,037
2020	2,284,260	233,402	583	27,256	4,226	2	2,549,730
2021	2,310,777	235,663	582	27,353	4,369	2	2,578,747
2022	2,337,689	237,945	581	27,439	4,512	2	2,608,168
2023	2,365,355	240,275	580	27,518	4,656	2	2,638,386
2024	2,392,778	242,594	579	27,592	4,799	2	2,668,344
2025	2,419,086	244,844	578	27,658	4,942	2	2,697,111
2026	2,444,031	247,009	577	27,715	5,085	2	2,724,420
2027	2,467,888	249,106	576	27,763	5,229	2	2,750,564
2028	2,491,035	251,158	575	27,805	5,372	2	2,775,947
2029	2,513,616	253,174	575	27,842	5,515	2	2,800,723
2030	2,535,787	255,164	574	27,873	5,658	2	2,825,059
2031	2,557,710	257,139	573	27,902	5,801	2	2,849,127
2032	2,579,168	259,086	572	27,927	5,945	2	2,872,700
2033	2,601,149	261,059	571	27,946	6,088	2	2,896,814

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2F – North Carolina Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	100,497	15,502	60	1,867	397	2	118,325
2009	100,761	15,485	59	1,867	398	2	118,573
2010	101,005	15,457	56	1,857	395	2	118,772
2011	101,009	15,418	53	1,852	392	2	118,726
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	102,694	15,667	60	1,862	394	1	120,679
2019	103,050	15,704	60	1,858	395	1	121,069
2020	103,385	15,738	60	1,855	396	1	121,435
2021	103,700	15,771	60	1,852	397	1	121,782
2022	104,021	15,804	60	1,850	398	1	122,134
2023	104,350	15,839	60	1,847	398	1	122,495
2024	104,676	15,872	60	1,845	399	1	122,854
2025	104,990	15,905	60	1,843	400	1	123,199
2026	105,287	15,937	60	1,842	401	1	123,527
2027	105,571	15,968	60	1,840	401	1	123,841
2028	105,846	15,998	60	1,839	402	1	124,146
2029	106,115	16,027	60	1,838	403	1	124,444
2030	106,379	16,056	60	1,837	404	1	124,737
2031	106,640	16,085	60	1,836	405	1	125,026
2032	106,895	16,113	60	1,835	405	1	125,310
2033	107,157	16,142	60	1,835	406	1	125,601

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2G – Zonal Summer and Winter Peak Demand (MW)

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2008	19,051	17,028
2009	18,137	17,904
2010	19,140	17,689
2011	20,061	17,889
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	19,938	18,666
2019	20,282	18,974
2020	20,568	19,291
2021	20,867	19,748
2022	21,161	20,191
2023	21,477	20,517
2024	22,010	20,862
2025	22,381	21,175
2026	22,757	21,534
2027	23,006	22,024
2028	23,228	22,394
2029	23,567	22,537
2030	23,960	22,696
2031	24,230	22,935
2032	24,422	23,161
2033	24,610	23,608

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2H – Summer & Winter Peaks for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

POWER SUPPLY DATA

Schedule 5

	(ACTUAL)				(PROJECTED)														
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	16,461	16,821	16,241	17,413	17,674	17,766	18,026	18,284	18,559	19,025	19,351	19,682	19,899	20,093	20,389	20,733	20,967	21,133	21,297
b. Other Commitments(2)	72	93	109	4	43	202	203	202	204	202	200	198	198	198	198	198	200	201	202
c. Total System Summer Peak	16,533	16,914	16,350	17,417	17,718	17,968	18,229	18,486	18,762	19,227	19,551	19,880	20,097	20,292	20,587	20,931	21,167	21,334	21,499
d. Percent Increase in Total Summer Peak	1.7%	2.3%	-3.3%	6.5%	1.7%	1.4%	1.5%	1.4%	1.5%	2.5%	1.7%	1.7%	1.1%	1.0%	1.5%	1.7%	1.1%	0.8%	0.8%
2. Winter																			
a. Adjusted Winter Peak(1)	18,616	16,080	16,509	16,038	16,261	16,380	16,772	17,160	17,439	17,736	18,009	18,320	18,743	19,061	19,185	19,322	19,527	19,721	20,104
b. Other Commitments(2)	72	93	109	-18.5	22	176	175	167	168	168	164	160	157	157	156	155	155	155	156
c. Total System Winter Peak	18,688	16,173	16,618	16,019	16,283	16,555	16,947	17,328	17,607	17,904	18,172	18,480	18,901	19,218	19,341	19,477	19,682	19,876	20,260
d. Percent Increase in Total Winter Peak	11.0%	-13.5%	2.8%	-3.6%	1.6%	1.7%	2.4%	2.2%	1.6%	1.7%	1.5%	1.7%	2.3%	1.7%	0.6%	0.7%	1.1%	1.0%	1.9%

(1) Adjusted load from Appendix 2I.

(2) Includes firm Additional Forecast, Conservation Efficiency, and Peak Adjustments from Appendix 2I.

Appendix 2I – Projected Summer & Winter Peak Load & Energy Forecast for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

Schedule 1

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]			(PROJECTED)															
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,530	16,914	16,350	17,417	17,718	17,968	18,229	18,486	18,762	19,227	19,551	19,880	20,097	20,292	20,587	20,931	21,167	21,334	21,499
1b. Additional Forecast																			
NCEMC	0	-	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-72	-93	-109	-154	-193	-202	-203	-202	-204	-202	-200	-198	-198	-198	-198	-198	-200	-201	-202
3. Demand Response[2][5]	-81	-103	-70	-99	-100	-100	-101	-101	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102
4. Demand Response-Existing[2][3]	-2	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
5. Peak Adjustment	-	-	-																
6. Adjusted Load	16,461	16,821	16,241	17,413	17,674	17,766	18,026	18,284	18,559	19,025	19,351	19,682	19,899	20,093	20,389	20,733	20,967	21,133	21,297
7. % Increase in Adjusted Load	0.7%	2.2%	-3.4%	7.2%	1.5%	0.5%	1.5%	1.4%	1.5%	2.5%	1.7%	1.7%	1.1%	1.0%	1.5%	1.7%	1.1%	0.8%	0.8%
(from previous year)																			
B. Winter																			
1a. Base Forecast	18,688	16,173	16,618	16,019	16,283	16,555	16,947	17,328	17,607	17,904	18,172	18,480	18,901	19,218	19,341	19,477	19,682	19,876	20,260
1b. Additional Forecast																			
NCEMC	0	-	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-72	-93	-109	-131.5	-172.2	-175.6	-175.2	-167.3	-168.2	-167.8	-163.5	-160.3	-157.4	-157.0	-156.0	-155.3	-154.7	-155.0	-155.6
3. Demand Response[2][4]	-5	-4	-5	-8	-8	-9	-9	-10	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
4. Demand Response-Existing[2][3]	-2	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
5. Adjusted Load	18,616	16,080	16,509	16,038	16,261	16,380	16,772	17,160	17,439	17,736	18,009	18,320	18,743	19,061	19,185	19,322	19,527	19,721	20,104
6. % Increase in Adjusted Load	9.9%	-13.6%	2.7%	-2.9%	1.4%	0.7%	2.4%	2.3%	1.6%	1.7%	1.5%	1.7%	2.3%	1.7%	0.7%	0.7%	1.1%	1.0%	1.9%
2. Energy (GWh)																			
A. Base Forecast	84,755	84,698	84,046	89,276	90,579	90,738	92,101	93,611	95,144	96,951	98,329	99,935	101,448	103,185	104,300	105,538	106,851	108,421	109,248
B. Additional Forecast																			
Future BTM[6]	-	-	-	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416
C. Conservation & Demand Response[5]	-460	-556	-660	-805	-930	-933	-882	-840	-836	-826	-811	-801	-795	-795	-795	-795	-798	-801	-805
D. Demand Response-Existing[2][3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	84,295	84,142	83,386	88,056	89,233	89,390	90,803	92,355	93,892	95,709	97,102	98,718	100,237	101,974	103,089	104,326	105,637	107,203	108,027
F. % Increase in Adjusted Energy	0.5%	-0.2%	-0.9%	5.6%	1.3%	0.2%	1.6%	1.7%	1.7%	1.9%	1.5%	1.7%	1.5%	1.7%	1.1%	1.2%	1.3%	1.5%	0.8%

(1) Actual metered data.

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

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

(4) Actual historical data based upon 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 BTMG, which is not included in the Base forecast.

Appendix 2J – Required Reserve Margin for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

POWER SUPPLY DATA (continued)

Schedule 6

	(ACTUAL)			(PROJECTED)																
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. Reserve Margin(1)																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW(1)	3,742	3,919	3,506	1,356	2,622	2,595	2,190	2,191	2,283	2,264	2,304	2,339	2,429	2,443	2,495	2,481	2,522	2,563	2,507
b. Percent of Load	22.7%	23.2%	21.4%	7.8%	14.8%	14.6%	12.2%	12.0%	12.3%	11.9%	11.9%	11.9%	12.2%	12.2%	12.2%	12.0%	12.0%	12.1%	11.8%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	6.9%	13.7%	13.5%	7.7%	3.8%	5.3%	5.6%	6.7%	7.8%	7.2%	6.7%	7.8%	8.6%	9.6%	9.3%	8.9%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	4,430	4,745	4,750	4,374	4,405	4,528	4,572	4,649	4,724	4,838	4,872	4,961	4,991	5,059	5,117	5,078
b. Percent of Load	N/A	N/A	N/A	27.6%	29.2%	29.0%	26.1%	25.7%	26.0%	25.6%	25.8%	25.8%	25.8%	25.6%	25.9%	25.8%	25.9%	25.9%	25.3%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin(1)(2)																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW(1)	3,742	3,919	3,506	1,356	2,622	2,595	2,190	2,191	2,283	2,264	2,304	2,339	2,429	2,443	2,495	2,481	2,522	2,563	2,507
b. Percent of Load	22.7%	23.2%	21.4%	7.8%	14.8%	14.6%	12.2%	12.0%	12.3%	11.9%	11.9%	11.9%	12.2%	12.2%	12.2%	12.0%	12.0%	12.1%	11.8%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	6.9%	13.7%	13.5%	7.7%	3.8%	5.3%	5.6%	6.7%	7.8%	7.2%	6.7%	7.8%	8.6%	9.6%	9.3%	8.9%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	4,430	4,745	4,750	4,374	4,405	4,528	4,572	4,649	4,724	4,838	4,872	4,961	4,991	5,059	5,117	5,078
b. Percent of Load	N/A	N/A	N/A	27.6%	29.2%	29.0%	26.1%	25.7%	26.0%	25.6%	25.8%	25.8%	25.8%	25.6%	25.9%	25.8%	25.9%	25.9%	25.3%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

Appendix 2K – Economic Assumptions used In the Sales and Hourly Budget Forecast Model (Annual Growth Rate)

Year	Economic Assumptions Used In the Sales and Hourly Budget Forecast Model (Annual Growth Rate)																
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	CAGR
Population: Total, (Ths.)	8,515	8,573	8,634	8,696	8,759	8,823	8,888	8,952	9,014	9,075	9,135	9,194	9,252	9,309	9,365	9,419	0.7%
Disposable Personal Income; (Mil. 09$; SAAR)	363,555	369,194	371,690	378,132	387,173	396,157	404,592	413,849	424,004	435,123	447,424	459,841	472,332	485,246	498,065	510,946	2.3%
Per Capita Disposable Personal Income; (C 09$; SAAR)	42.7	43.1	43.1	43.5	44.2	44.9	45.5	46.2	47.0	48.0	49.0	50.0	51.1	52.1	53.2	54.3	1.6%
Residential Permits: Total, (#, SAAR)	33,671	38,269	41,608	42,926	42,490	41,125	40,044	40,088	39,574	37,906	36,837	36,021	35,410	34,978	34,459	33,850	0.0%
Employment: Total Manufacturing, (Ths., SA)	233	231	226	223	222	219	216	213	211	208	206	203	201	199	197	195	-1.2%
Employment: Total Government, (Ths., SA)	718.8	723.0	726.4	732.2	738.8	745.1	750.4	755.6	760.9	766.4	772.1	778.0	783.9	789.5	793.9	798.0	0.7%
Employment: Military personnel, (Ths., SA)	140	138	136	134	134	133	133	132	132	131	131	131	130	130	129	129	-0.6%
Employment: State and local government, (Ths., SA)	540	544	547	552	559	565	570	575	580	585	591	597	602	607	612	615	0.9%
Employment: Commercial Sector (Ths., SA)	2,878.8	2,907.4	2,909.2	2,932.1	2,969.3	3,003.3	3,025.2	3,044.4	3,064.9	3,084.2	3,106.5	3,127.7	3,147.6	3,168.7	3,190.5	3,213.8	0.7%
Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR)	38,731	39,439	39,564	40,605	41,365	41,785	42,108	42,589	43,153	43,705	44,363	44,984	45,547	46,146	46,751	47,379	1.4%
Gross State Product: Total; (Bil. Chained 2009 $; SAAR)	460.8	471.0	476.2	488.6	500.5	510.6	519.8	529.9	540.6	551.2	562.9	574.3	585.4	596.6	608.0	619.6	2.0%
Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR)	36,483	36,681	36,843	37,446	38,096	38,766	39,329	39,871	40,433	41,002	41,564	42,072	42,553	43,026	43,501	43,978	1.25%

Source: Economy.com October 2017 vintage

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	CAGR
Population: Total, (Ths.)	8,509	8,574	8,640	8,706	8,772	8,836	8,900	8,964	9,027	9,089	9,150	9,210	9,269	9,327	9,384	9,439	0.7%
Disposable Personal Income; (Mil. 09$; SAAR)	365,950	377,278	387,490	394,384	401,240	409,165	417,599	426,195	435,536	445,512	456,403	467,756	479,593	491,709	504,174	516,539	2.3%
Per Capita Disposable Personal Income; (C 09$; SAAR)	43.0	44.0	44.9	45.3	45.8	46.3	46.9	47.6	48.3	49.0	49.9	50.8	51.8	52.7	53.7	54.7	1.6%
Residential Permits: Total, (#, SAAR)	42,506	48,313	45,191	40,717	40,897	42,895	43,159	41,366	38,737	36,428	35,057	34,060	33,036	32,699	32,105	30,863	-2.1%
Employment: Total Manufacturing, (Ths., SA)	228	227	226	223	220	216	214	211	208	206	204	202	200	198	196	195	-1.1%
Employment: Total Government, (Ths., SA)	718.7	721.4	724.9	729.1	734.3	740.3	745.8	750.8	755.9	761.3	766.7	772.3	778.1	783.8	789.2	793.4	0.7%
Employment: Military personnel, (Ths., SA)	135	133	131	129	128	127	127	126	126	125	125	124	124	124	123	123	-0.6%
Employment: State and local government, (Ths., SA)	539	542	545	549	554	560	565	570	575	580	586	591	596	602	607	611	0.8%
Employment: Commercial Sector (Ths., SA)	2,844.4	2,895.8	2,946.0	2,970.3	2,983.4	3,003.2	3,029.1	3,053.0	3,077.3	3,102.5	3,127.5	3,152.7	3,179.0	3,206.0	3,234.0	3,263.5	0.9%
Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR)	39,054	39,979	40,547	40,828	41,230	41,727	42,317	42,896	43,490	44,138	44,831	45,550	46,269	46,973	47,674	48,352	1.4%
Gross State Product: Total; (Bil. Chained 2009 $; SAAR)	459.0	473.2	483.8	491.2	500.1	510.5	521.3	531.6	542.1	553.2	564.6	575.9	587.3	598.7	610.1	621.5	2.0%
Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR)	35,094	35,409	35,616	35,798	36,188	36,640	37,058	37,452	37,852	38,256	38,638	38,979	39,307	39,623	39,929	40,247	0.92%

Source: Economy.com October 2016 vintage

Appendix 3A – Existing Generation Units in Service

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Winter
Altavista	Altavista, VA	Base	Renewable	Feb-1992	51	51
Bath County 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,808	1,808
Bear Garden	Buckingham County, VA	Intermediate	Natural Gas-CC	May-2011	622	654
Bellemeade	Richmond, VA	Intermediate	Natural Gas-CC	Mar-1991	0	0
Bremo 3	Bremo Bluff, VA	Peak	Natural Gas	Jun-1950	0	0
Bremo 4	Bremo Bluff, VA	Peak	Natural Gas	Aug-1958	0	0
Brunswick	Brunswick County, VA	Intermediate	Natural Gas-CC	May-2016	1,376	1,470
Chesapeake CT 1, 2, 4, 6	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	51	69
Chesterfield 3	Chester, VA	Base	Coal	Dec-1952	0	0
Chesterfield 4	Chester, VA	Base	Coal	Jun-1960	0	0
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	336	342
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	670	690
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197	226
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	200	236
Clover 1	Clover, VA	Base	Coal	Oct-1995	220	222
Clover 2	Clover, VA	Base	Coal	Mar-1996	219	219
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	98
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	97
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	95
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	97
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	121
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	120
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	124
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	139
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	139
Gravel Neck 1-2	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28	38
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	85	98
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	97
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	98
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85	97
Hopewell	Hopewell, VA	Base	Renewable	Jul-1989	51	51
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161	183
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160	183
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160	183
Lowmoor CT 1-4	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48	65
Mecklenburg 1	Clarksville, VA	Base	Coal	Nov-1992	0	0
Mecklenburg 2	Clarksville, VA	Base	Coal	Nov-1992	0	0

(1) Commercial Operation Date

Appendix 3A cont. – Existing Generation Units in Service

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Winter
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	554	569
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	555	570
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	520	537
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11	15
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	838	868
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834	863
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1	1
Northern Neck CT 1-4	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47	70
Pittsylvania	Hurt, VA	Base	Renewable	Jun-1994	0	0
Possum Point 3	Dumfries, VA	Peak	Natural Gas	Jun-1955	0	0
Possum Point 4	Dumfries, VA	Peak	Natural Gas	Apr-1962	0	0
Possum Point 5	Dumfries, VA	Peak	Heavy Fuel Oil	Jun-1975	786	805
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	573	615
Possum Point CT 1-6	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72	106
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153	187
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151	187
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	187
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	188
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95	95
Rosemary	Roanoke Rapids, NC	Peak	Natural Gas-CC	Dec-1990	165	165
Scott Solar	Powhatan, VA	Intermittent	Renewable	Dec-2016	4	17
Solar Partnership Program	Distributed	Intermittent	Renewable	Jan-2012	2	7
Southampton	Franklin, VA	Base	Renewable	Mar-1992	51	51
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	838	875
Surry 2	Surry, VA	Base	Nuclear	May-1973	838	875
Virginia City Hybrid Energy Center	Virginia City, VA	Base	Coal	Jul-2012	610	624
Warren	Front Royal, VA	Intermediate	Natural Gas-CC	Dec-2014	1,342	1,436
Whitehouse Solar	Louisa, VA	Intermittent	Renewable	Dec-2016	5	20
Woodland Solar	Isle of Wight, VA	Intermittent	Renewable	Dec-2016	4	19
Yorktown 1	Yorktown, VA	Base	Coal	Jul-1957	0	0
Yorktown 2	Yorktown, VA	Base	Coal	Jan-1959	0	0
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	790	792
Subtotal - Base					7,185	7,406
Subtotal - Intermediate					6,652	7,039
Subtotal - Peak					4,413	4,931
Subtotal - Intermittent					15	63
Total					18,265	19,440

Note: Summer MW for solar generation represents firm capacity.

(1) Commercial Operation Date.

Appendix 3B – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units[1]							
SEI Birchwood	King George, VA	Base	Coal	217,800	Yes	11/15/1996	11/14/2021
Behind-The-Meter (BTM) Generation Units							
Alexandria/Arlington - Covanta	VA	NUG	MSW	21,000	No	1/29/1988	1/28/2023
Brasfield Dam	VA	Must Take	Hydro	2,500	No	10/12/1993	Auto renew
Suffolk Landfill	VA	Must Take	Methane	3,000	No	11/4/1994	Auto renew
Columbia Mills	VA	Must Take	Hydro	343	No	2/7/1985	Auto renew
Lakeview (Swift Creek) Dam	VA	Must Take	Hydro	400	No	11/26/2008	Auto renew
MeadWestvaco (formerly Westvaco)	VA	NUG	Coal/Biomass	140,000	No	11/3/1982	9/30/2028
Banister Dam	VA	Must Take	Hydro	1,785	No	9/28/2008	Auto renew
Jockey's Ridge State Park	NC	Must Take	Wind	10	No	5/21/2010	Auto renew
302 First Flight Run	NC	Must Take	Solar	3	No	5/5/2010	Auto renew
3620 Virginia Dare Trail N	NC	Must Take	Solar	4	No	9/14/2009	Auto renew
Weyerhaeuser/Domtar	NC	NUG	Coal/biomass	28,400[2]	No	7/27/1991	Auto renew
Chapman Dam	VA	Must Take	Hydro	300	No	10/17/1984	Auto renew
Smurfit-Stone Container	VA	NUG	Coal/biomass	48,400[3]	No	3/21/1981	Auto renew
Rivanna	VA	Must Take	Hydro	100	No	4/21/1998	Auto renew
Rapidan Mill	VA	Must Take	Hydro	100	No	6/15/2009	Auto renew
Burnshire Dam	VA	Must Take	Hydro	100	No	7/11/2016	Auto renew
Dairy Energy	VA	Must Take	Biomass	400	No	8/2/2011	7/31/2019
Essex Solar Center	VA	Must Take	Solar	20,000	No	12/14/2017	12/13/2037
W. E. Partners II	NC	Must Take	Biomass	300	No	3/15/2012	Auto renew
Plymouth Solar	NC	Must Take	Solar	5,000	No	10/4/2012	10/3/2027
W. E. Partners 1	NC	Must Take	Biomass	100	No	4/26/2013	Auto renew
Dogwood Solar	NC	Must Take	Solar	20,000	No	12/9/2014	12/8/2029
HXOap Solar	NC	Must Take	Solar	20,000	No	12/16/2014	12/15/2029
Bethel Price Solar	NC	Must Take	Solar	5,000	No	12/9/2014	12/8/2029
Jakana Solar	NC	Must Take	Solar	5,000	No	12/4/2014	12/3/2029
Lewiston Solar	NC	Must Take	Solar	5,000	No	12/18/2014	12/17/2029
Williamston Solar	NC	Must Take	Solar	5,000	No	12/4/2014	12/3/2029
Windsor Solar	NC	Must Take	Solar	5,000	No	12/17/2014	12/16/2029
510 REPP One Solar	NC	Must Take	Solar	1,250	No	3/11/2015	3/10/2030
Everetts Wildcat Solar	NC	Must Take	Solar	5,000	No	3/11/2015	3/10/2030
SolNC5 Solar	NC	Must Take	Solar	5,000	No	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Must Take	Solar	14,000	No	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Must Take	Solar	5,000	No	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Must Take	Solar	5,000	No	11/1/2015	10/31/2030
Downs Farm Solar	NC	Must Take	Solar	5,000	No	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Must Take	Solar	5,000	No	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Must Take	Solar	5,000	No	12/18/2015	12/17/2030
Green Farm Solar	NC	Must Take	Solar	5,000	No	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Must Take	Solar	20,000	No	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Must Take	Solar	20,000	No	1/28/2016	1/27/2031
Bradley PVI- FAE IX	NC	Must Take	Solar	5,000	No	2/4/2016	2/3/2031
Conetoe Solar	NC	Must Take	Solar	5,000	No	2/5/2016	2/4/2031
SolNC3 Solar-Sugar Run Solar	NC	Must Take	Solar	5,000	No	2/5/2016	2/4/2031
Gates Solar	NC	Must Take	Solar	5,000	No	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Must Take	Solar	5,000	No	2/12/2016	2/11/2031
Battleboro Farm Solar	NC	Must Take	Solar	5,000	No	2/17/2016	2/16/2031
Winton Solar	NC	Must Take	Solar	5,000	No	2/8/2016	2/7/2031
SolNC10 Solar	NC	Must Take	Solar	5,000	No	1/13/2016	1/12/2031

(1) In operation as of March 1, 2018.

(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 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Behind-The-Meter (BTM) Generation Units							
Tarboro Solar	NC	Must Take	Solar	5,000	No	12/31/2015	12/30/2030
Bethel Solar	NC	Must Take	Solar	4,400	No	3/3/2016	3/2/2031
Garysburg Solar	NC	Must Take	Solar	5,000	No	3/18/2016	3/17/2031
Woodland Solar	NC	Must Take	Solar	5,000	No	4/7/2016	4/6/2031
Gaston Solar	NC	Must Take	Solar	5,000	No	4/18/2016	4/17/2031
TWE Kelford Solar	NC	Must Take	Solar	4,700	No	6/6/2016	6/5/2031
FAE XVIII - Meadows	NC	Must Take	Solar	20,000	No	6/9/2016	6/8/2031
Seaboard Solar	NC	Must Take	Solar	5,000	No	6/29/2016	6/28/2031
Simons Farm Solar	NC	Must Take	Solar	5,000	No	7/13/2016	7/12/2031
Whitakers Farm Solar	NC	Must Take	Solar	3,400	No	7/20/2016	7/19/2031
MC1 Solar	NC	Must Take	Solar	5,000	No	8/19/2016	8/18/2031
Williamston West Farm Solar	NC	Must Take	Solar	5,000	No	8/23/2016	8/22/2031
River Road Solar	NC	Must Take	Solar	5,000	No	8/23/2016	8/22/2031
White Farm Solar	NC	Must Take	Solar	5,000	No	8/26/2016	8/25/2031
Hardison Farm Solar	NC	Must Take	Solar	5,000	No	9/9/2016	9/8/2031
Modlin Farm Solar	NC	Must Take	Solar	5,000	No	9/14/2016	9/13/2031
Battleboro Solar	NC	Must Take	Solar	5,000	No	10/7/2016	10/6/2031
Williamston Speight Solar	NC	Must Take	Solar	15,000	No	11/23/2016	11/22/2031
Barnhill Road Solar	NC	Must Take	Solar	3,100	No	11/30/2016	11/29/2031
Hemlock Solar	NC	Must Take	Solar	5,000	No	12/5/2016	12/4/2031
Leggett Solar	NC	Must Take	Solar	5,000	No	12/14/2016	12/13/2031
Schell Solar Farm	NC	Must Take	Solar	5,000	No	12/22/2016	12/21/2031
FAE XXXV - Turkey Creek	NC	Must Take	Solar	13,500	No	1/31/2017	1/30/2027
FAE XXII - Baker PVI	NC	Must Take	Solar	5,000	No	1/30/2017	1/29/2032
FAE XXI -Benthall Bridge PVI	NC	Must Take	Solar	5,000	No	1/30/2017	1/29/2032
Aulander Hwy 42 Solar	NC	Must Take	Solar	5,000	No	12/30/2016	12/29/2031
Floyd Road Solar	NC	Must Take	Solar	5,000	No	6/19/2017	6/18/2032
Flat Meeks- FAE II	NC	Must Take	Solar	5,000	No	10/27/2017	10/26/2032
HXNAir Solar One	NC	Must Take	Solar	5,000	No	12/21/2017	12/20/2032
Cork Oak Solar	NC	Must Take	Solar	20,000	No	12/29/2017	12/28/2032
Sunflower Solar	NC	Must Take	Solar	16,000	No	12/29/2017	12/28/2032
Davis Lane Solar	NC	Must Take	Solar	5,000	No	12/31/2017	12/30/2032
FAE XIX- American Legion PVI	NC	Must Take	Solar	15,840	No	1/2/2018	1/1/2033
FAE XXV-Vaughn's Creek	NC	Must Take	Solar	20,000	No	1/2/2018	1/1/2033
TWE Ahoskie Solar Project	NC	Must Take	Solar	5,000	No	1/12/2018	1/11/2033
Cottonwood Solar	NC	Must Take	Solar	3,000	No	1/25/2018	1/24/2033
Shiloh Hwy 1108 Solar	NC	Must Take	Solar	5,000	No	2/9/2018	2/8/2033
Chowan Jehu Road Solar	NC	Must Take	Solar	5,000	No	2/9/2018	2/8/2033
Phelps 158 Solar Farm	NC	Must Take	Solar	5,000	No	2/26/2018	2/25/2033

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	25000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	Natural Gas	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	VA Beach	Standby	Diesel	3500	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/ Natural Gas	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	Natural Gas	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	Natural Gas	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	Natural Gas	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	Natural Gas	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black Liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Natural Gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Ashburn	Standby	Diesel	22000	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	NG	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	Va Beach	Standby	Diesel	3500	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/NG	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	NG	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	NG	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	NG	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	NG	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Nat gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Norfolk	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Norfolk	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Newport News	Standby	Diesel	750	No	N/A	N/A
	Chesterfield	Standby	Coal	500	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Richmond Metro	Standby	NG	25000	No	N/A	N/A
	Suffolk	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	21000	No	N/A	N/A
	Richmond	Standby	Diesel	500	No	N/A	N/A
	Hampton Roads	Standby	Diesel	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	12000	No	N/A	N/A
	West Point	Standby	Unknown	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	100	No	N/A	N/A
	Herndon	Standby	Diesel	18100	No	N/A	N/A
	VA'	Merchant	RDF	60000	No	N/A	N/A
	Stafford	Standby	Diesel	3000	No	N/A	N/A
	Chesterfield	Standby	Diesel	750	No	N/A	N/A
	Henrico	Standby	Diesel	750	No	N/A	N/A
	Richmond	Standby	Diesel	5150	No	N/A	N/A
	Culpepper	Standby	Diesel	7000	No	N/A	N/A
	Richmond	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Northern VA	Standby	NG	50000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Hampton Roads	Standby	Unknown	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	13000	No	N/A	N/A
	Southside VA	Standby	Water	227000	No	N/A	N/A
	Northern VA	Standby	Diesel	300	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	30	No	N/A	N/A
	Newport News	Standby	Diesel	1000	No	N/A	N/A
	Hampton	Standby	Diesel	12000	No	N/A	N/A
	Newport News	Standby	Natural gas	3000	No	N/A	N/A
	Newport News	Standby	Diesel	2000	No	N/A	N/A
	Petersburg	Standby	Diesel	1750	No	N/A	N/A
	Various	Standby	Diesel	3000	No	N/A	N/A
	Various	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	16000	No	N/A	N/A
	Northern VA	Standby	Diesel	6450	No	N/A	N/A
	Virginia Beach	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	12 - 2000	No	N/A	N/A
	Innsbrook-Richmond	Standby	Diesel	6050	No	N/A	N/A
	Northern VA	Standby	Diesel	150	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Virginia Beach	Standby	Diesel	1500	No	N/A	N/A
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	30000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A

Part 4

Appendix 3C – Equivalent Availability Factor for Plan E: Federal CO_2 Program (%)

Company Name: Virginia Electric and Power Company — Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2015 (ACTUAL)	2016	2017	2018 (PROJECTED)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Altavista	67	63	63	77	78	78	78	78	74	74	74	74	74	74	74	74	74	74	74
Bath County 1-6	77	80	90	93	94	94	94	95	95	95	95	95	95	95	95	95	95	98	98
Bear Garden	81	85	80	89	80	86	84	84	88	89	88	90	89	88	89	78	78	87	87
Bellemeade	83	80	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	78	86	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	80	83	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	83	82	82	80	83	83	76	93	85	93	79	93	93	85	93	93	84	84
Chesapeake CT 1, 2, 4, 6	92	98	99	91	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	85	86	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	65	75	55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	83	74	65	82	84	81	81	84	86	86	86	86	86	86	86	86	86	86	86
Chesterfield 6	84	74	59	71	85	85	79	85	87	87	87	87	87	87	87	87	87	87	87
Chesterfield 7	90	67	84	73	94	89	96	87	96	91	96	89	96	81	96	91	96	81	87
Chesterfield 8	90	66	85	88	96	73	96	87	96	89	96	89	96	89	96	89	96	80	88
Clover 1	76	88	88	88	83	93	92	94	94	86	92	92	92	92	92	92	92	92	92
Clover 2	90	88	65	92	90	92	83	94	86	94	94	94	94	94	94	94	94	94	94
CVOW	-	-	-	-	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45
Darbytown 1	96	91	92	93	83	93	93	93	88	88	88	88	88	88	88	88	88	93	93
Darbytown 2	80	97	93	95	84	94	94	94	90	90	90	90	90	90	90	90	90	93	93
Darbytown 3	91	98	89	95	84	94	94	94	90	90	90	90	90	90	90	90	90	93	93
Darbytown 4	92	92	92	95	84	94	94	94	90	90	90	90	90	90	90	90	90	93	93
Elizabeth River 1	99	98	93	95	91	94	94	94	89	89	89	89	89	89	89	89	89	90	90
Elizabeth River 2	97	98	92	95	90	94	94	94	89	89	89	89	89	89	89	89	89	90	90
Elizabeth River 3	99	71	92	95	94	91	94	91	90	90	90	90	90	90	90	90	90	90	90
Existing NC Solar NUGs	20	20	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Existing VA Solar NUGs	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Gaston Hydro	88	90	91	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Generic 2x1 CC				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Aero CT				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Brownfield CT	-	-	-	-	-	-	-	87	87	87	87	87	87	87	87	87	87	87	87
Generic Greenfield CT	-	-	-	-	-	-	-	-	-	87	87	87	87	87	87	87	87	87	87
Generic Solar PV	-	-	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Gordonsville 1	81	89	77	97	84	93	93	86	97	91	97	86	97	91	97	86	97	87	93
Gordonsville 2	83	91	52	97	93	93	86	89	97	91	97	84	91	97	91	97	91	93	93
Gravel Neck 1-2	96	96	100	91	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	89	96	90	95	94	94	94	91	90	90	90	90	90	90	90	90	90	94	94
Gravel Neck 4	90	97	87	95	91	94	94	94	90	90	90	90	90	90	90	90	90	94	94
Gravel Neck 5	92	97	91	92	94	94	94	94	90	90	90	90	90	90	90	90	90	94	94
Gravel Neck 6	91	97	91	95	94	94	94	91	90	90	90	90	90	90	90	90	90	94	94

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

Appendix 3C cont. – Equivalent Availability Factor for Plan E: Federal CO_2 Program (%)

Company Name: Virginia Electric and Power Company — Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)			(PROJECTED)															
Unit Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Greensville	-	-	-	96	82	83	83	83	90	90	90	90	90	90	90	90	90	84	84
Hopewell	64	74	78	77	78	78	78	77	74	74	74	74	74	74	74	74	74	74	74
Ladysmith 1	93	90	85	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 2	92	90	85	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 3	94	91	84	80	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 4	94	91	77	71	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 5	94	90	83	90	80	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Lowmoor CT 1-4	98	98	98	91	91	100	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	84	95	93	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	82	96	93	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	80	82	74	72	68	83	78	72	75	83	81	75	83	81	75	83	81	86	86
Mount Storm 2	78	80	81	72	81	79	72	81	75	81	81	75	81	81	75	81	86	86	86
Mount Storm 3	79	65	70	87	81	73	82	73	75	84	84	75	84	84	75	84	87	87	87
Mount Storm CT	57	100	96	91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	92	90	100	89	92	98	91	91	98	91	91	98	91	91	98	91	91	98	91
North Anna 2	100	88	90	98	89	91	98	91	91	98	91	91	98	91	91	98	91	91	91
North Anna Hydro	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Northern Neck CT 1-4	100	98	94	91	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	88	60	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	89	71	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	83	69	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	33	52	62	81	80	80	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	80	80	75	91	77	84	80	80	88	88	88	76	88	88	88	88	88	87	87
Possum Point CT 1-6	100	99	97	91	90	90	100	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	91	91	91	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 2	86	92	91	91	90	90	87	90	90	90	90	90	90	90	90	90	90	90	90
Remington 3	89	90	70	91	90	90	87	87	90	90	90	90	90	90	90	90	90	90	90
Remington 4	92	92	83	91	90	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Roanoke Rapids Hydro	88	90	93	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Rosemary	68	81	77	94	96	83	96	96	89	96	89	96	89	96	89	96	89	94	94
Scott Solar	-	2	21	25	25	24	24	24	24	24	24	24	24	23	23	23	23	23	23
SEI Birchwood	90	90	87	80	80	80	74	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Southampton	74	69	68	78	77	79	77	77	74	74	74	74	74	74	74	74	74	74	74
Surry 1	75	94	99	91	90	98	91	91	98	91	91	98	91	91	98	91	91	93	93
Surry 2	81	99	92	89	98	91	91	98	91	91	98	91	91	98	91	91	98	98	93
US-3 Solar 1	-	-	-	-	-	28	28	28	28	28	28	28	28	28	28	28	28	28	28
US-3 Solar 2	-	-	-	-	-	-	27	27	27	27	27	27	27	27	27	27	27	27	27
Virginia City Hybrid Energy Center	86	76	74	76	75	80	77	80	77	77	77	77	77	77	71	77	77	88	88
Warren	61	81	88	79	83	83	75	83	85	93	93	77	89	86	93	93	93	85	85
Whitehouse Solar	-	2	20	25	25	25	25	24	24	24	24	24	24	24	24	23	23	23	23
Woodland Solar	-	2	18	25	25	25	25	25	25	25	24	24	24	24	24	24	24	24	24
Yorktown 1	79	87	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	84	91	97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	35	59	83	82	81	81	81	-	-	-	-	-	-	-	-	-	-	-	-

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

Appendix 3D – Net Capacity Factor for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 9**
UNIT PERFORMANCE DATA
Net Capacity Factor (%)

Unit Name	(ACTUAL) 2015	2016	2017	2018	(PROJECTED) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Altavista	60.1	63.1	61.7	75.2	75.2	74.9	73.6	74.8	11.5	11.6	12.9	16.0	17.5	16.3	18.2	18.1	20.6	21.8	29.3
Bath County 1-6	13.8	12.3	14.2	24.3	23.7	20.9	19.7	19.8	19.6	19.7	19.3	18.8	18.3	18.4	18.7	18.6	18.2	17.7	18.0
Bear Garden	67.0	69.7	62.1	78.1	70.6	72.3	71.8	72.5	72.4	75.5	74.7	76.2	74.6	65.4	64.8	49.0	48.1	55.1	57.9
Bellemeade	53.2	39.9	7.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	6.5	10.3	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	12.7	24.6	8.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	51.0	67.8	74.7	73.3	79.2	77.6	71.5	85.6	79.0	83.6	74.2	84.0	81.6	77.4	79.3	79.7	70.1	73.6
Chesapeake CT 1, 2, 4, 6	0.2	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	12.6	6.2	4.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	23.4	53.7	16.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	69.8	59.4	43.4	29.1	25.7	24.2	21.1	18.6	18.2	17.4	16.8	17.3	18.9	14.6	15.3	12.2	12.1	10.9	11.6
Chesterfield 6	69.8	63.0	31.3	26.8	31.3	32.9	25.9	23.7	22.4	22.3	21.3	23.9	25.8	20.3	20.4	17.3	15.8	14.2	16.2
Chesterfield 7	94.7	70.6	89.7	64.8	86.6	80.6	86.9	78.1	84.1	78.8	82.6	75.6	81.6	64.7	79.1	70.9	75.8	61.6	70.0
Chesterfield 8	96.4	69.7	90.2	81.8	87.9	65.0	84.2	76.8	81.4	76.2	79.4	73.5	79.1	70.9	76.0	68.3	71.9	59.2	66.8
Clover 1	65.3	69.4	48.0	41.2	39.8	43.7	39.5	37.2	38.8	35.9	18.4	16.7	19.9	15.0	14.1	11.7	11.3	10.1	10.8
Clover 2	77.5	72.0	37.1	46.4	44.4	47.5	41.6	42.7	40.9	43.5	19.8	21.5	23.1	17.4	18.5	13.4	13.8	12.2	14.3
CVOW	-	-	-	-	-	-	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	4.2	0.9	1.9	3.5	3.5	2.8	1.9	1.6	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Darbytown 2	3.1	0.9	1.8	3.5	3.5	2.9	1.9	1.8	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Darbytown 3	5.2	1.2	2.7	3.5	3.5	2.9	2.1	1.8	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Darbytown 4	5.9	1.4	8.7	3.5	3.5	2.9	1.9	1.8	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Elizabeth River 1	7.2	3.7	3.4	4.6	4.6	4.2	4.5	4.0	3.7	3.8	3.7	3.2	3.4	3.2	3.2	3.3	3.3	3.1	3.2
Elizabeth River 2	6.1	7.0	3.5	4.6	4.6	4.2	4.5	4.0	3.7	3.8	3.7	3.2	3.4	3.2	3.2	3.3	3.3	3.1	3.2
Elizabeth River 3	0.9	5.0	3.2	4.6	4.6	4.2	4.5	4.0	3.7	3.8	3.6	3.2	3.4	3.2	3.2	3.2	3.2	3.1	3.2
Existing NC Solar NUGs	-	-	-	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	25.4	25.4
Existing VA Solar NUGs	-	-	-	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	25.4	25.4
Gaston Hydro	16.4	21.2	14.1	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Generic 2x1 CC				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Aero CT	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Brownfield CT	-	-	-	-	-	-	-	7.0	7.1	7.7	8.0	9.3	7.7	5.9	6.0	5.1	4.5	4.8	5.8
Generic Greenfield CT	-	-	-	-	-	-	-	-	-	7.5	8.0	9.3	7.8	6.4	6.7	5.8	5.1	5.3	6.2
Generic Solar PV	-	-	-	-	-	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
Gordonsville 1	57.8	47.1	14.2	53.4	45.3	42.0	36.2	36.1	38.7	41.0	40.4	36.0	39.5	31.9	36.5	27.0	29.9	24.8	31.0
Gordonsville 2	61.7	48.9	9.6	55.0	55.1	43.3	36.5	41.6	41.1	43.4	42.0	40.1	37.7	35.6	37.4	32.8	31.8	27.7	34.0
Gravel Neck 1-2	-	0.1	0.1	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	1.1	5.3	4.3	5.9	5.9	5.1	5.2	5.0	4.7	4.9	5.1	4.7	4.7	4.5	4.5	4.2	4.2	4.0	4.3
Gravel Neck 4	4.5	5.4	0.9	5.9	5.9	5.1	5.2	5.0	4.7	5.0	5.1	4.7	4.7	4.6	4.5	4.2	4.2	4.0	4.3
Gravel Neck 5	3.6	5.1	3.9	5.9	5.9	5.1	5.2	5.0	4.7	4.9	5.1	4.7	4.7	4.5	4.5	4.2	4.2	4.0	4.3
Gravel Neck 6	3.0	2.7	0.8	5.9	5.9	5.1	5.2	5.0	4.7	5.0	5.1	4.7	4.7	4.6	4.5	4.2	4.2	4.0	4.3

Appendix 3D cont. – Net Capacity Factor for Plan E: Federal CO_2 Program

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

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

	(ACTUAL)									(PROJECTED)									
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Greensville	-	-	-	8.0	78.9	79.6	79.7	79.8	86.0	86.2	85.4	85.3	85.6	84.5	85.3	85.1	84.5	78.8	79.9
Hopewell	58.8	68.3	66.0	68.8	64.9	67.6	65.3	66.9	9.2	8.7	8.7	10.2	12.4	11.4	12.4	13.7	16.1	16.4	22.3
Ladysmith 1	4.1	7.0	9.4	10.1	10.1	10.0	10.1	10.1	10.1	9.6	9.8	9.9	10.0	8.1	8.6	8.5	8.8	7.6	7.9
Ladysmith 2	3.3	15.3	11.1	10.1	10.1	10.0	10.1	10.1	10.1	9.6	9.8	9.8	10.1	8.1	8.8	8.5	8.7	7.5	7.9
Ladysmith 3	10.1	11.4	5.7	10.1	10.1	10.0	10.1	10.1	10.1	10.0	9.9	9.9	10.1	8.3	8.9	8.8	8.9	7.6	8.2
Ladysmith 4	9.4	9.6	9.4	9.4	10.1	10.0	10.1	10.1	10.1	9.9	9.9	9.7	10.1	8.3	9.2	8.6	9.0	7.6	8.1
Ladysmith 5	5.3	12.8	6.5	10.1	9.8	10.0	10.1	10.1	10.1	10.0	9.9	10.0	10.1	8.3	9.2	8.6	9.0	7.6	8.1
Lowmoor CT 1-4	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	28.0	25.6	12.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	27.6	23.8	12.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	70.3	68.4	49.4	50.1	47.0	59.0	53.5	52.1	52.0	49.0	47.5	48.6	52.3	46.0	48.3	42.8	38.1	36.9	40.1
Mount Storm 2	65.9	67.0	58.0	50.8	56.0	57.7	52.5	55.3	52.3	48.2	48.4	48.3	51.7	46.7	48.9	42.5	38.8	36.8	39.8
Mount Storm 3	70.9	53.3	39.1	55.6	50.2	47.8	47.7	43.9	42.6	43.2	41.6	42.2	46.9	40.3	38.2	33.9	32.7	29.9	33.3
Mount Storm CT	0.1	0.2	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	93.8	91.6	102.3	87.3	90.6	96.3	89.1	89.0	96.3	88.9	89.0	96.3	88.8	89.0	96.3	88.8	89.0	96.3	88.8
North Anna 2	102.6	90.4	92.3	96.4	87.3	89.4	96.4	89.0	89.1	96.4	88.9	89.1	96.4	88.9	89.1	96.4	88.9	89.1	88.9
North Anna Hydro	41.4	41.4	29.2	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6
Northern Neck CT 1-4	-	0.1	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	36.8	20.1	15.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	1.3	2.2	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	1.4	3.5	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	3.5	1.3	0.9	6.0	6.0	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	66.4	67.2	59.1	85.5	72.5	78.8	74.2	74.6	80.4	80.0	79.0	67.6	78.5	75.7	76.4	75.0	74.1	70.6	73.4
Possum Point CT 1-6	-	0.0	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	18.4	13.0	9.9	17.3	15.1	10.9	9.1	9.2	9.1	9.2	9.4	8.6	8.3	7.2	7.7	7.7	7.5	7.3	7.3
Remington 2	16.6	14.0	9.8	17.3	15.2	10.9	9.1	9.1	9.1	9.1	9.4	8.7	8.3	7.2	7.6	7.7	7.5	7.2	7.3
Remington 3	15.7	11.0	10.0	17.5	16.1	11.3	9.1	9.3	9.4	9.3	9.5	8.8	8.4	7.4	7.8	7.7	7.6	7.1	7.3
Remington 4	16.5	12.1	8.7	16.3	16.0	11.1	10.3	10.7	10.5	10.3	10.5	10.2	9.4	8.2	8.7	8.6	8.5	8.1	8.2
Roanoke Rapids Hydro	34.9	43.1	25.7	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4
Rosemary	7.8	5.2	9.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Scott Solar	-	2.1	20.6	24.7	24.6	24.4	24.3	24.2	24.1	23.9	23.8	23.7	23.6	23.5	23.4	23.2	23.1	23.0	22.9
SEI Birchwood	27.2	21.6	22.8	52.2	53.8	50.1	41.3	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Southampton	65.0	66.1	62.5	61.0	52.7	55.0	50.3	54.1	6.1	6.2	6.5	6.6	8.2	6.9	8.8	8.3	9.7	10.7	16.0
Surry 1	77.2	96.6	102.4	89.2	87.9	95.9	88.7	88.4	95.9	88.7	88.4	95.9	88.7	88.4	95.9	88.7	88.4	91.0	91.0
Surry 2	83.4	101.9	94.2	87.3	95.9	89.0	88.4	95.9	88.7	88.4	95.9	88.7	88.4	95.9	88.7	88.4	95.9	95.9	91.0
US-3 Solar 1	-	-	-	-	-	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
US-3 Solar 2	-	-	-	-	-	-	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2
Virginia City Hybrid Energy Center	55.5	65.4	62.4	58.7	55.7	63.7	62.1	64.5	62.8	57.7	59.8	64.3	62.6	58.6	58.1	56.6	55.1	52.9	54.3
Warren	54.7	72.3	75.7	72.3	74.4	75.3	65.7	74.7	75.4	82.5	81.8	69.2	77.0	72.0	77.7	74.4	75.0	66.9	70.6
Whitehouse Solar	-	2.1	19.9	24.9	24.8	24.6	24.5	24.4	24.3	24.2	24.0	23.9	23.8	23.7	23.6	23.5	23.3	23.2	23.1
Woodland Solar	-	2.1	17.8	25.3	25.2	25.1	25.0	24.8	24.7	24.6	24.5	24.3	24.2	24.1	24.0	23.9	23.7	23.6	23.5
Yorktown 1	10.5	3.4	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	8.0	19.7	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	4.4	2.1	1.1	3.0	3.0	3.0	3.0	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 3E – Heat Rates for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 10**
UNIT PERFORMANCE DATA
Average Heat Rate - (mmBtu/MWh)

Unit Name	2015 (ACTUAL)	2016	2017	2018 (PROJECTED)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Altavista	14.26	15.07	15.16	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31
Bath County 1-6			-																
Bear Garden	7.12	6.79	6.54	7.13	7.12	7.12	7.12	7.13	7.13	7.12	7.12	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13
Bellemeade	8.62	8.72	8.77																
Bremo 3	12.06	12.37	12.30																
Bremo 4	10.59	10.45	10.54																
Brunswick	-	8.34	6.96	6.88	6.88	6.88	6.88	6.88	6.88	6.86	6.87	6.84	6.87	6.87	6.86	6.87	6.87	6.87	6.87
Chesapeake CT 1, 2, 4, 6	16.98	16.98	16.90	0.00	0.00														
Chesterfield 3	12.45	13.05	13.68																
Chesterfield 4	10.52	10.46	11.07																
Chesterfield 5	10.16	10.27	10.23	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
Chesterfield 6	9.98	10.07	10.25	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94
Chesterfield 7	7.40	7.45	7.53	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	7.23	7.30	7.38	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	9.99	10.06	10.31	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53
Clover 2	10.00	10.06	10.21	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44
CVOW																			
Darbytown 1	12.54	12.60	12.45	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	12.56	12.47	12.35	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	12.51	12.38	12.36	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	12.58	12.48	12.43	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	11.69	11.86	12.06	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	11.72	12.12	12.24	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	11.23	12.32	12.11	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
Existing NC Solar NUGs																			
Existing VA Solar NUGs																			
Gaston Hydro																			
Generic 2x1 CC																			
Generic Aero CT																			
Generic Brownfield CT								10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07
Generic Greenfield CT										10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07
Generic Solar PV																			
Gordonsville 1	8.47	8.17	8.60	8.16	8.17	8.16	8.16	8.17	8.18	8.16	8.16	8.17	8.16	8.16	8.16	8.17	8.16	8.16	8.16
Gordonsville 2	8.45	8.17	8.51	8.15	8.15	8.15	8.15	8.16	8.15	8.15	8.15	8.15	8.16	8.15	8.15	8.15	8.15	8.15	8.15
Gravel Neck 1-2	20.17	19.08	17.88	17.40	0.00														
Gravel Neck 3	12.79	12.57	12.61	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	12.82	12.57	13.02	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	13.22	12.99	13.09	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	12.55	12.72	12.79	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 3E cont. – Heat Rates for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company — Schedule 10

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

Unit Name	2015 (ACTUAL)	2016	2017	2018 (PROJECTED)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Greensville	-		-	6.44	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67
Hopewell	15.75	15.32	15.98	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09
Ladysmith 1	10.09	10.06	9.96	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	9.86	9.68	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
Ladysmith 3	9.94	9.89	9.99	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	9.86	9.92	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 5	9.90	9.83	9.98	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	17.83	16.59	16.86	0.00	0.00	0.00													
Mecklenburg 1	11.89	11.95	12.49																
Mecklenburg 2	12.20	12.38	12.50																
Mount Storm 1	9.99	10.13	10.16	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	9.93	10.07	10.05	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91
Mount Storm 3	10.42	10.39	10.56	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	21.83	16.75	16.03	0.00	0.00														
North Anna 1	-	-		10.40	10.39	10.40	10.40	10.39	10.40	10.41	10.39	10.40	10.41	10.39	10.40	10.41	10.39	10.40	10.41
North Anna 2	-	-		10.42	10.44	10.41	10.42	10.43	10.41	10.42	10.43	10.41	10.42	10.43	10.41	10.42	10.44	10.41	10.44
North Anna Hydro																			
Northern Neck CT 1-4	18.19	16.32	16.87	0.00	0.00	0.00													
Pittsylvania	15.98	17.36	14.76																
Possum Point 3	12.21	12.95	11.62																
Possum Point 4	12.98	11.49	11.86																
Possum Point 5	10.26	11.19	11.87	9.93	9.93	9.93													
Possum Point 6	7.19	7.13	7.18	7.43	7.42	7.42	7.39	7.38	7.41	7.40	7.40	7.38	7.40	7.39	7.39	7.39	7.39	7.38	7.39
Possum Point CT 1-6	17.04	17.98	17.32	0.00	0.00	0.00	0.00												
Remington 1	9.97	10.02	10.01	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	10.17	10.05	10.10	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	10.30	10.26	10.03	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	10.12	10.09	9.99	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	9.55	9.50	9.48	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																			
SEI Birchwood	10.00	10.00	10.00	9.61	9.61	9.61	9.61												
Solar Partnership Program																			
Southampton	15.16	15.31	15.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70
Surry 1	-	-		10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.31
Surry 2	-	-		10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.31	10.31
US-3 Solar 1																			
US-3 Solar 2																			
Virginia City Hybrid Energy Center	9.96	9.87	10.02	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	6.77	6.91	6.88	6.93	6.93	6.94	6.93	6.92	6.93	6.94	6.93	6.94	6.93	6.93	6.94	6.94	6.94	6.95	6.94
Whitehouse Solar																			
Woodland Solar																			
Yorktown 1	10.70	11.54	12.09																
Yorktown 2	10.68	11.63	12.25																
Yorktown 3	10.79	10.55	10.86	10.15	10.15	10.15	10.15												

Appendix 3F – Existing Capacity for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company
CAPACITY DATA

Schedule 7

	(ACTUAL)								(PROJECTED)										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. Installed 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. Coal	4,400	4,081	4,077	3,638	3,644	3,638	3,632	3,626	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623
c. Heavy Fuel Oil	1,575	1,575	1,572	1,576	1,576	1,576	790	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	596	596	596	246	167	119	47	47	47	47	47	47	47	47	47	47	47	47	47
e. Natural Gas-Boiler	543	543	543	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f. Natural Gas-Combined Cycle	3,543	4,919	4,948	4,693	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278
g. Natural Gas-Turbine	2,052	2,053	2,053	2,426	2,426	2,426	2,426	2,884	3,342	3,800	4,258	4,716	4,716	4,716	5,174	5,632	6,090	6,090	6,090
h. Hydro-Conventional	317	317	317	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
i. Pumped 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
j. Renewable	236	236	236	213	207	318	439	554	665	756	864	973	1,081	1,190	1,280	1,353	1,371	1,479	1,588
k. Total Company Installed	18,428	19,486	19,509	18,265	19,771	19,828	19,085	18,861	19,428	19,976	20,543	21,109	21,218	21,326	21,875	22,405	22,881	22,990	23,098
l. Other (NUG)	1,775	1,252	238	346	366	372	372	153	152	152	151	150	149	149	148	147	146	145	144
n. Total	20,203	20,738	19,746	18,611	20,137	20,201	19,456	19,014	19,580	20,128	20,694	21,259	21,367	21,475	22,023	22,552	23,028	23,134	23,242
II. Installed Capacity Mix (%)(2)																			
a. Nuclear	16.6%	16.2%	17.0%	18.0%	16.6%	16.6%	17.2%	17.6%	17.1%	16.6%	16.2%	15.8%	15.7%	15.6%	15.2%	14.8%	14.5%	14.5%	14.4%
b. Coal	21.8%	19.7%	20.6%	19.5%	18.1%	18.0%	18.7%	19.1%	18.5%	18.0%	17.5%	17.0%	17.0%	16.9%	16.4%	16.1%	15.7%	15.7%	15.6%
c. Heavy Fuel Oil	7.8%	7.6%	8.0%	8.5%	7.8%	7.8%	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%
d. Light Fuel Oil	3.0%	2.9%	3.0%	1.3%	0.8%	0.6%	0.2%	0.00	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas-Boiler	2.7%	2.6%	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%
f. Natural Gas-Combined Cycle	17.5%	23.7%	25.1%	25.2%	31.2%	31.1%	32.3%	33.0%	32.1%	31.2%	30.3%	29.5%	29.4%	29.2%	28.5%	27.8%	27.3%	27.1%	27.0%
g. Natural Gas-Turbine	10.2%	9.9%	10.4%	13.0%	12.0%	12.0%	12.5%	15.2%	17.1%	18.9%	20.6%	22.2%	22.1%	22.0%	23.5%	25.0%	26.4%	26.3%	26.2%
h. Hydro-Conventional	1.6%	1.5%	1.6%	1.7%	1.6%	1.6%	1.6%	1.7%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%
i. Pumped Storage	9.0%	8.7%	9.2%	9.7%	9.0%	9.0%	9.3%	9.5%	9.2%	9.0%	8.7%	8.5%	8.5%	8.4%	8.2%	8.0%	7.9%	7.8%	7.8%
j. Renewable	1.2%	1.1%	1.2%	1.1%	1.0%	1.6%	2.3%	2.9%	3.4%	3.8%	4.2%	4.6%	5.1%	5.5%	5.8%	6.0%	6.0%	6.4%	6.8%
k. Total Company Installed	91.2%	94.0%	98.8%	98.1%	98.2%	98.2%	98.1%	99.2%	99.2%	99.2%	99.3%	99.3%	99.3%	99.3%	99.3%	99.3%	99.4%	99.4%	99.4%
l. Other (NUG)	8.8%	6.0%	1.2%	1.9%	1.8%	1.8%	1.9%	0.8%	0.8%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
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%

(1) Net dependable installed capability during peak season.
(2) Each item in Section I as a percent of line n (Total).

Appendix 3G – Energy Generation by Type for Plan E: Federal CO_2 Program (GWh)

Company Name: Virginia Electric and Power Company — Schedule 2

GENERATION

	(ACTUAL)			(PROJECTED)															
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. System Output (GWh)																			
a. Nuclear	26,173	27,978	28,883	27,457	27,575	28,331	27,640	27,617	28,207	27,699	27,618	28,207	27,618	27,696	28,207	27,618	27,614	28,461	27,422
b. Coal	22,618	21,974	15,376	15,313	14,578	15,738	14,346	14,131	13,734	13,160	12,211	12,718	13,422	11,725	11,633	10,529	9,886	9,326	10,030
c. Heavy Fuel Oil	542	236	141	631	631	633	208	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	319	222.8	131.1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas-Boiler	253	487.5	163.4	554	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f. Natural Gas-Combined Cycle	18,482	25,563	26,832	33,339	43,340	44,093	42,676	42,822	46,212	46,399	46,682	43,004	46,045	43,757	44,395	42,736	42,864	39,420	41,168
g. Natural Gas-Turbine	1,606	1,692	1,246	2,386	2,294	1,940	1,807	2,089	2,356	2,749	3,121	3,654	3,327	2,774	3,169	3,140	3,185	3,128	3,487
h. Hydro-Conventional	1,039	1,333	876	513	513	514	513	513	513	514	513	513	513	514	513	513	513	514	513
i. Hydro-Pumped Storage	2,217	1,971	2,367	3,850	3,748	3,323	3,120	3,143	3,101	3,137	3,050	2,977	2,906	2,918	2,970	2,941	2,887	2,813	2,853
j. Renewable(1)	1,191	1,246	1,265	1,684	1,252	2,419	3,548	4,657	4,958	5,833	6,900	8,012	9,092	10,149	11,026	11,730	11,926	13,028	14,147
k. Total Generation	74,440	82,703	77,081	85,727	93,932	96,991	93,858	94,972	99,081	99,491	100,094	99,084	102,923	99,533	101,912	99,206	98,876	96,690	99,621
l. Purchased Power	14,657	7,486	13,419	14,351	9,917	8,648	10,356	9,341	8,080	9,041	8,905	11,260	9,746	12,530	11,502	14,611	15,599	17,885	16,622
m. Total Payback Energy(2)	-			9	7	8	8	8	7	8	6	9	9	11	11	11	11	11	11
n. Less Pumping Energy	-2,800	-2,480	-3,014	-4,813	-4,685	-4,135	-3,900	-3,929	-3,885	-3,932	-3,784	-3,722	-3,632	-3,656	-3,723	-3,676	-3,607	-3,499	-3,567
o. Less Other Sales(3)	-1,716	-4,296	-1,536	-7,303	-10,030	-12,220	-9,628	-8,151	-9,509	-9,018	-8,229	-8,034	-8,927	-6,560	-6,729	-5,942	-5,359	-4,002	-4,777
p. Total System Firm Energy Req.	84,581	83,414	85,951	87,963	89,134	89,283	90,687	92,233	93,767	95,583	96,976	98,587	100,109	101,847	102,962	104,200	105,508	107,075	107,898
II. Energy Supplied by Competitive Service Providers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Include current estimates for renewable energy generation by VCHEC.

(2) Payback Energy is accounted for in Total Generation.

(3) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

180510037

Appendix 3H – Energy Generation by Type for Plan E: Federal CO_2 Program (%)

Company Name: Virginia Electric and Power Company

GENERATION

Schedule 3

	(ACTUAL)			(PROJECTED)															
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
III. System Output Mix (%)																			
a. Nuclear	30.9%	33.5%	33.4%	31.2%	30.9%	31.7%	30.5%	29.9%	30.1%	29.0%	28.5%	28.6%	27.6%	27.2%	27.4%	26.5%	26.2%	26.6%	25.4%
b. Coal	26.7%	26.3%	17.9%	17.4%	16.4%	17.6%	15.8%	15.3%	14.6%	13.8%	12.6%	12.9%	13.4%	11.5%	11.3%	10.1%	9.4%	8.7%	9.3%
c. Heavy Fuel Oil	0.6%	0.3%	0.2%	0.7%	0.7%	0.7%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
d. Light Fuel Oil	0.4%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	0.3%	0.6%	0.2%	0.6%	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%
f. Natural Gas-Combined Cycle	21.9%	30.6%	31.2%	37.9%	48.6%	49.4%	47.1%	46.4%	49.3%	48.5%	48.1%	43.6%	46.0%	43.0%	43.1%	41.0%	40.6%	36.8%	38.2%
g. Natural Gas-Turbine	1.9%	2.0%	1.4%	2.7%	2.6%	2.2%	2.0%	2.3%	2.5%	2.9%	3.2%	3.7%	3.3%	2.7%	3.1%	3.0%	3.0%	2.9%	3.2%
h. Hydro-Conventional	1.2%	1.6%	1.0%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
i. Hydro-Pumped Storage	2.6%	2.4%	2.8%	4.4%	4.2%	3.7%	3.4%	3.4%	3.3%	3.3%	3.1%	3.0%	2.9%	2.9%	2.9%	2.8%	2.7%	2.6%	2.6%
j. Renewable Resources	1.4%	1.5%	1.5%	1.9%	1.4%	2.7%	3.9%	5.0%	5.3%	6.1%	7.1%	8.1%	9.1%	10.0%	10.7%	11.3%	11.3%	12.2%	13.1%
k. Total Generation	88.0%	99.1%	89.7%	97.5%	105.4%	108.6%	103.5%	103.0%	105.7%	104.1%	103.2%	100.5%	102.8%	97.7%	99.0%	95.2%	93.7%	90.3%	92.3%
l. Purchased Power	17.3%	9.0%	15.6%	16.3%	11.1%	9.7%	11.4%	10.1%	8.6%	9.5%	9.2%	11.4%	9.7%	12.3%	11.2%	14.0%	14.8%	16.7%	15.4%
m. Direct Load Control (DLC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
n. Less Pumping Energy	-3.3%	-3.0%	-3.5%	-5.5%	-5.3%	-4.6%	-4.3%	-4.3%	-4.1%	-4.1%	-3.9%	-3.8%	-3.6%	-3.6%	-3.6%	-3.5%	-3.4%	-3.3%	-3.3%
o. Less Other Sales(1)	-2.0%	-5.1%	-1.8%	-8.3%	-11.3%	-13.7%	-10.6%	-8.8%	-10.1%	-9.4%	-8.5%	-8.1%	-8.9%	-6.4%	-6.5%	-5.7%	-5.1%	-3.7%	-4.4%
p. Total System Output	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	58.5%	57.9%	58.6%	57.7%	57.6%	57.3%	57.5%	57.7%	57.8%	57.3%	57.3%	57.3%	57.5%	57.8%	57.7%	57.4%	57.5%	57.8%	57.9%

(1) Economy energy.

Appendix 3I – Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company

Schedule 13a

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate

Unit Name	(ACTUAL) 2015	2016	2017	2018	(PROJECTED) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Altavista	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 2, 4, 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing NC Solar NUGs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing VA Solar NUGs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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

Appendix 3I cont. – Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company — **Schedule 13a**

UNIT PERFORMANCE DATA[(1)]
Unit Size (MW) Uprate and Derate

Unit Name	(ACTUAL) 2015	2016	2017	2018	(PROJECTED) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Greensville	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scott Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SEI Birchwood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City Hybrid Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Whitehouse Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Woodland Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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

Appendix 3J – Potential Unit Retirements

Company Name: Virginia Electric and Power Company | Schedule 19

UNIT PERFORMANCE DATA

Planned Unit Retirements[1]

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Yorktown 1[4]	Yorktown, VA	Steam-Cycle	Coal	2017	159	162
Yorktown 2[4]	Yorktown, VA	Steam-Cycle	Coal	2017	164	165
Chesapeake CT 1	Chesapeake, VA	CombustionTurbine	Light Fuel Oil	2019	15	20
Chesapeake GT1					15	
Chesapeake CT 2	Chesapeake, VA	CombustionTurbine	Light Fuel Oil	2019	36	49
Chesapeake GT2					12	
Chesapeake GT4					12	
Chesapeake GT6					12	
Gravel Neck 1	Surry, VA	CombustionTurbine	Light Fuel Oil	2019	28	38
Gravel Neck GT1					12	
Gravel Neck GT2					16	
Lowmoor CT	Covington, VA	CombustionTurbine	Light Fuel Oil	2020	48	65
Low moor GT1					12	
Low moor GT2					12	
Low moor GT3					12	
Low moor GT4					12	
Mount Storm CT	Mt. Storm, WV	CombustionTurbine	Light Fuel Oil	2018	11	15
Mt. Storm GT1					11	
Northern Neck CT	Warsaw, VA	CombustionTurbine	Light Fuel Oil	2020	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	2021	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	
Bellemeade CC[3]	Richmond, VA	Combined Cycle	Natural Gas	2021	267	267
Bremo 3[2]	New Canton, VA	Steam-Cycle	Natural Gas	2021	71	71
Bremo 4[2]	New Canton, VA	Steam-Cycle	Natural Gas	2021	156	156
Clover 1[4]	Clover, VA	Steam-Cycle	Coal	2025	220	222
Clover 2	Clover, VA	Steam-Cycle	Coal	2025	219	219
Chesterfield 3[3]	Chester, VA	Steam-Cycle	Coal	2021	98	102
Chesterfield 4[3]	Chester, VA	Steam-Cycle	Coal	2021	163	168
Chesterfield 5	Chester, VA	Steam-Cycle	Coal	2023	336	342
Chesterfield 6	Chester, VA	Steam-Cycle	Coal	2023	670	690
Mecklenburg 1[2]	Clarksville, VA	Steam-Cycle	Coal	2021	69	69
Mecklenburg 2[2]	Clarksville, VA	Steam-Cycle	Coal	2021	69	69
Pittsylvania[5]	Hurt, VA	Steam-Cycle	Biomass	2021	83	83
Possum Point 3[3]	Dumfries, VA	Steam-Cycle	Natural Gas	2021	96	100
Possum Point 4[3]	Dumfries, VA	Steam-Cycle	Natural Gas	2021	220	225
Possum Point 5	Dumfries, VA	Steam-Cycle	Heavy Fuel Oil	2021	786	805
Yorktown 3	Yorktown, VA	Steam-Cycle	Heavy Fuel Oil	2022	790	792

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

(2) These units entered into cold reserve in April 2018.

(3) These units are planned to enter into cold reserve in December 2018.

(4) Yorktown Units 1 and 2 ceased operations on April 15, 2017 to comply with the MATS rule. Since that time, PJM requested the units to be available on an emergency basis.

(5) Pittsylvania is planned to enter cold reserve in August 2018.

Appendix 3K – Generation under Construction

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

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer[2]	MW Nameplate
Under Construction						
Greensville County Power Station	VA	Intermediate/Baseload	Natural Gas	2019	1,585	1,585

(1) Commercial Operation Date.
(2) Firm capacity.

Appendix 3L – Wholesale Power Sales Contracts

Company Name: Virginia Electric and Power Company

WHOLESALE POWER SALES CONTRACTS

Schedule 20

			(Actual)				(Projected)														
Entity	Contract Length	Contract Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements(1)	12	6	10	9	9	9	9	10	10	10	10	11	11	11	11	11	11	11	11
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements(1)	11	11	11	10	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements(1)	309	350	299	285	287	291	293	295	297	300	302	304	307	311	313	317	320	323	326

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

Appendix 3M – 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 -2043
NC Duration:	2011- 2043

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 – 2043

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 3M cont. – Description of Active DSM Programs

Non-Residential Heating and Cooling Efficiency Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2043
NC Duration:	2015 – 2043

Program Description:
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing heating, ventilating, and air conditioning ("HVAC") 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 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.

Non-Residential Lighting Systems & Controls Program

Target Class:	Non-Residential
VA Program Type :	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2043
NC Duration:	2015 – 2043

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 efficient fluorescent bulbs, 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 these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Appendix 3M 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:	2014 – 2043
NC Duration:	2015 – 2043

Program Description:
This Program provides qualifying non-residential customers with an incentive to install solar reduction window film to lower their cooling bills and improve occupant comfort. Customers can receive rebates for installing qualified solar reduction window film in non-residential facilities based on the Solar Heat Gain Coefficient of window film installed.

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.

Income and Age Qualifying Home Improvement Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2015 – 2043
NC Duration:	2016 – 2043

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.

Appendix 3M cont. – Description of Active DSM Programs

Residential Retail LED Lighting Program (NC only)

Target Class:	Residential
NC Program Type:	Energy Efficiency
NC Duration:	2017 – 2033

Program Description:
This Program provides residential customers in the Company's North Carolina service territory with an instant discount for qualifying LED light bulb purchases from a participating retailer. Qualifying bulbs will be those types that are commonly used, including general service (A-line) bulbs, specialty bulbs (candelabra base, globe, and reflector) and small fixtures meeting Energy Star and UL standards.

Program Marketing:
The instant rebate will be marketed using a combination of in-store point-of purchase, direct mail, social media, and online communications.

Small Business Improvement Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2016 – 2043
NC Duration:	2017 – 2043

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 3M 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 – 2043
NC Duration:	2018 – 2043

Program Description:
This Program will provide 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 would offer 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 will utilize the contractor network to market the programs to customers as well.

Appendix 3N – Approved Programs Non-Coincidental Peak Savings for Plan E: Federal CO_2 Program (kW) (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	91,285	91,285	91,285	91,285	91,285	91,285	91,285	93,909	97,141	98,467	95,812	93,918	91,285	91,285	91,285	91,285
Residential Low Income Program	4,079	4,079	4,079	4,079	4,079	4,079	4,041	3,511	2,235	1,437	796	192	0	0	0	0
Residential Lighting Program	27,995	27,349	19,445	9,772	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	10,118	10,118	9,164	8,825	2,412	87	67	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	668	668	668	668	668	668	668	656	495	193	0	0	0	0	0	0
Non-Residential Energy Audit Program	5,656	5,654	5,029	3,155	702	335	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452
Non-Residential Distributed Generation Program	8,416	8,416	9,468	9,468	10,520	10,541	10,563	10,584	10,605	10,626	10,647	10,668	10,689	10,710	10,731	10,752
Residential Bundle Program	24,655	24,478	22,329	20,064	18,274	18,212	17,221	13,139	9,915	7,110	6,712	5,589	4,312	2,653	339	289
Residential Home Energy Check-Up Program	11,442	11,442	11,442	11,442	11,441	11,379	10,387	6,305	3,081	279	0	0	0	0	0	0
Residential Duct Sealing Program	353	353	353	353	353	353	353	353	353	353	353	353	353	351	339	289
Residential Heat Pump Tune Up Program	6,380	6,202	4,054	1,789	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	6,481	6,481	6,481	6,481	6,481	6,481	6,481	6,481	6,481	6,478	6,359	5,236	3,959	2,302	0	0
Non-Residential Window Film Program	34,093	49,232	51,712	54,241	56,821	58,162	58,602	59,034	59,450	59,853	60,245	60,630	61,009	61,384	61,755	62,126
Non-Residential Lighting Systems & Controls Program	42,316	43,473	44,654	45,858	47,085	48,022	55,450	55,411	53,050	48,316	48,483	48,647	48,808	48,967	49,125	49,282
Non-Residential Heating and Cooling Efficiency Program	34,729	47,946	50,101	52,295	54,529	55,698	56,093	56,481	56,856	57,218	57,571	57,917	58,257	58,595	59,466	59,262
Income and Age Qualifying Home Improvement Program	2,131	2,488	2,919	3,499	4,078	4,567	4,596	4,625	4,653	4,680	4,705	4,730	4,754	4,777	4,781	4,824
Residential Appliance Recycling Program	1,720	1,720	1,720	1,720	1,720	1,492	993	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	4,494	8,621	13,754	16,210	16,621	16,883	17,025	17,164	17,299	17,429	17,556	17,680	17,921	20,176	21,313	21,433
Residential Retail LED Lighting Program (NC only)	1,813	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977
Non-Residential Prescriptive Program	6,761	14,231	22,725	31,219	34,572	35,081	35,370	35,685	35,989	36,283	36,569	36,850	37,127	37,401	37,672	37,944
Total	329,382	370,187	379,482	380,788	373,796	375,541	382,404	380,628	378,118	372,040	369,524	367,249	364,590	366,378	366,896	367,626

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

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Appendix 3O – Approved Programs Coincidental Peak Savings for Plan E: Federal CO_2 Program (kW) (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285
Residential Low Income Program	2,346	2,346	2,346	2,346	2,346	2,346	2,192	1,640	1,052	842	274	50	0	0	0	0
Residential Lighting Program	19,877	16,666	10,404	3,154	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	10,118	10,118	9,160	5,331	1,336	87	36	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	668	668	668	668	668	668	668	582	340	88	0	0	0	0	0	0
Non-Residential Energy Audit Program	5,287	5,285	4,748	2,360	659	225	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013
Non-Residential Distributed Generation Program	8,149	8,416	9,030	9,468	10,082	10,533	10,554	10,575	10,596	10,617	10,638	10,659	10,680	10,701	10,722	10,743
Residential Bundle Program	18,382	15,446	13,761	12,283	11,579	11,467	9,990	7,938	6,103	5,208	4,632	3,737	2,634	1,223	242	142
Residential Home Energy Check-Up Program	6,440	6,440	6,440	6,440	6,438	6,325	4,848	2,796	961	78	0	0	0	0	0	0
Residential Duct Sealing Program	266	266	266	266	266	266	266	266	266	266	266	266	265	261	242	142
Residential Heat Pump Tune Up Program	4,800	3,864	2,179	702	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	4,876	4,876	4,876	4,876	4,876	4,876	4,876	4,876	4,876	4,864	4,366	3,471	2,369	963	0	0
Non-Residential Window Film Program	23,381	35,622	37,413	39,239	41,101	42,070	42,382	42,680	42,968	43,232	43,498	43,776	44,049	44,320	44,588	44,856
Non-Residential Lighting Systems & Controls Program	25,640	30,603	31,450	32,313	33,192	33,639	33,770	33,899	34,023	34,144	34,261	34,376	34,489	34,601	34,712	34,823
Non-Residential Heating and Cooling Efficiency Program	27,747	40,863	42,700	44,570	46,474	47,470	47,807	48,138	48,457	48,766	49,066	49,361	49,651	49,939	50,223	50,508
Income and Age Qualifying Home Improvement Program	1,182	1,538	1,883	2,229	2,574	2,728	2,746	2,763	2,779	2,795	2,810	2,824	2,838	2,852	2,866	2,880
Residential Appliance Recycling Program	1,633	1,633	1,633	1,633	1,633	1,416	738	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	3,772	8,368	13,747	16,364	16,783	17,043	17,188	17,329	17,466	17,598	17,727	17,854	18,117	20,208	21,664	21,788
Residential Retail LED Lighting Program (NC only)	601	922	922	922	922	922	922	922	922	922	922	922	922	922	922	922
Non-Residential Prescriptive Program	4,658	12,524	20,390	28,256	31,956	32,433	32,731	33,023	33,306	33,579	33,844	34,105	34,362	34,616	34,867	35,119
Total	253,739	293,318	302,552	303,434	303,605	305,345	304,022	301,788	300,312	299,888	299,971	299,962	300,042	301,881	303,104	304,078

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3P – Approved Programs Energy Savings for Plan E: Federal CO_2 Program (MWh) (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Low Income Program	10,442	10,442	10,442	10,442	10,442	10,442	9,833	7,516	4,814	2,983	1,323	257	0	0	0	0
Residential Lighting Program	208,284	176,936	111,858	38,201	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	82,457	82,457	75,328	45,025	11,789	705	321	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	5,851	5,851	5,867	5,851	5,851	5,851	5,867	5,150	3,083	841	0	0	0	0	0	0
Non-Residential Energy Audit Program	38,155	38,143	32,687	16,938	4,614	1,636	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720
Non-Residential Distributed Generation Program	1	1,010	0	1	2	6	3	1	184	1	1	1	1	2	1	0
Residential Bundle Program	70,043	67,240	61,277	55,856	52,912	52,377	45,275	34,034	24,199	18,793	16,800	13,640	9,802	4,880	871	557
Residential Home Energy Check-Up Program	34,584	34,584	34,584	34;584	34,574	34,038	26,937	15,696	5,861	492	0	0	0	0	0	0
Residential Duct Sealing Program	947	947	947	947	947	947	947	947	947	947	947	947	946	932	871	557
Residential Heat Pump Tune Up Program	17,121	14,318	8,354	2,934	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,353	15,853	12,693	8,855	3,948	0	0
Non-Residential Window Film Program	25,660	39,033	40,999	43,005	45,051	46,110	46,460	46,805	47,138	47,463	47,778	48,083	48,384	48,681	48,975	49,270
Non-Residential Lighting Systems & Controls Program	159,339	193,288	198,635	204,087	209,646	212,664	213,495	214,311	215,099	215,860	216,601	217,328	218,044	218,753	219,453	220,155
Non-Residential Heating and Cooling Efficiency Program	70,367	108,956	113,859	118,852	123,935	126,804	127,705	128,590	129,445	130,270	131,074	131,863	132,639	133,408	134,168	134,928
Income and Age Qualifying Home Improvement Program	6,155	7,677	9,430	11,182	12,935	13,834	13,923	14,010	14,092	14,171	14,247	14,321	14,393	14,464	14,534	14,604
Residential Appliance Recycling Program	11,492	11,492	11,492	11,492	11,492	10,066	5,433	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	17,389	33,401	52,153	61,749	63,212	64,147	64,853	65,149	65,628	66,091	66,541	66,984	67,717	72,365	75,775	76,202
Residential Retail LED Lighting Program (NC only)	4,087	6,557	6,557	6,557	6,557	6,557	6;557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557
Non-Residential Prescriptive Program	29,124	81,731	134,339	186,946	213,532	216,827	218,822	220,780	222,671	224,498	226,278	228,021	229,739	231,439	233,121	234,803
Total	804,567	929,936	932,643	881,906	839,671	835,746	826,066	810,623	800,632	795,228	794,919	794,774	794,995	798,268	801,175	804,797

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3Q – Approved Programs Penetrations for Plan E: Federal CO_2 Program (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180
Residential Low Income Program	12,743	12,743	12,743	12,743	12,743	12,743	11,312	7,192	4,656	2,653	653	0	0	0	0	0
Residential Lighting Program	5,890,547	4,259,629	2,243,150	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	2,456	2,456	2,057	749	21	21	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	127	127	127	127	127	127	127	89	40	0	0	0	0	0	0	0
Non-Residential Energy Audit Program	1,740	1,739	1,437	305	154	17	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	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10
Residential Bundle Program	151,592	126,324	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
Residential Home Energy Check-Up Program	52,963	52,963	52,963	52,963	52,932	51,363	31,661	16,805	1,549	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	3,853	3,853	3,845	3,737	3,336	1,153
Residential Heat Pump Tune Up Program	75,568	50,300	22,879	2,597	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	19,208	19,208	19,122	15,827	12,134	7,327	1,267	0	0
Non-Residential Window Film Program	1,989,415	2,091,424	2,195,473	2,301,603	2,409,856	2,428,224	2,446,496	2,464,234	2,481,300	2,497,824	2,513,995	2,529,888	2,545,573	2,561,137	2,576,481	2,592,032
Non-Residential Lighting Systems & Controls Program	5,400	5,550	5,703	5,859	6,018	6,042	6,065	6,088	6,110	6,131	6,152	6,172	6,193	6,213	6,232	6,252
Non-Residential Heating and Cooling Efficiency Program	1,183	1,237	1,292	1,348	1,405	1,415	1,425	1,435	1,444	1,453	1,462	1,471	1,479	1,488	1,496	1,505
Income and Age Qualifying Home Improvement Program	17,399	21,899	26,399	30,899	35,399	35,628	35,856	36,074	36,280	36,478	36,670	36,857	37,041	37,223	37,401	37,583
Residential Appliance Recycling Program	14,072	14,072	14,072	14,072	14,072	10,866	3,131	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	1,797	2,787	3,934	4,017	4,102	4,131	4,160	4,188	4,215	4,242	4,267	4,292	4,317	4,342	4,366	4,391
Residential Retail LED Lighting Program (NC only)	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124
Non-Residential Prescriptive Program	460	916	1,372	1,828	1,870	1,887	1,905	1,921	1,937	1,953	1,968	1,983	1,998	2,013	2,027	2,042
Total	8,449,937	6,901,909	4,967,669	2,813,178	2,922,768	2,938,534	2,926,207	2,922,105	2,921,601	2,934,717	2,945,855	2,957,659	2,968,781	2,978,427	2,992,348	3,005,968

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3R – List of Transmission Lines under Construction

Line Terminals	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #47 Kings Dominion to Fredericksburg Rebuild	115	353	May-18	VA
Line #2183 Brambleton to Poland Road – New 230 kV Line and New 230kV Substation	230	1,047	May-18	VA
Line #2174 Vint Hill to Wheeler – New 230 kV Line	230	1,047	Jun-18	VA
Line #553 Cunningham to Elmont Rebuild	500	4,330	Jun-18	VA
Line #1009 Ridge Road to Chase City Rebuild	115	346	Jun-18	VA
Line #1020 Pantego to Trowbridge – New 115 kV Line	115	346	Jun-18	NC
Line #1015 Scotland Neck to South Justice Branch – New 115 kV Line	115	346	Sep-18	NC
Line #2086 Remington Combustion Turbine to Warrenton Rebuild	230	1,047	Oct-18	VA
Line #2161 Wheeler to Gainesville Uprate	230	1,047	Dec-18	VA
Line #54 Carolina to Woodland Reconductor	115	174	Dec-18	NC
Line #171 Chase City to Boydton Plank Road	115	393	Jun-19	VA
Line #90 Carolina to Kerr Dam Rebuild	115	346	Dec-19	VA/NC
Line #4 Bremo to Cartersville Uprate	115	151	May-18	VA
Line #48 Sewells Point to Thole Street and Line #107 Oakwood to Sewells Point Partial Rebuild	115	317 (#48) 353 (#107)	Dec-18	VA
Line #585 Carsons to Rogers Road Rebuild	500	4,330	Dec-18	VA
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild	115	353 (#34)	May-19	VA
Line #582 Surry to Skiffes Creek – New 500 kV Line	500	4,330	May-19	VA
Line #2138 Skiffes Creek to Whealton – New 230 kV Line	230	1,047	May-19	VA
Line #159 Acca to Hermitage Reconductor	115	353	May-19	VA
Line #534 Cunningham to Dooms Rebuild	500	4,330	Jun-19	VA
Line #171 Chase City to Boydton Plank Road Rebuild	115	393	Jun-19	VA
Line #82 Everetts to Leggetts Crossroads Delivery Point Rebuild	115	353	Dec-19	NC
Line #130 Clubhouse to Carolina Rebuild	115	394	Dec-19	VA/NC

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

Fall 2017 Forecast

NOTICE PROVISIONS FOR AUTHORIZED THIRD PARTY USERS.

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ICF Federal CO_2 Commodity Price Forecast (Nominal $)

	Fuel Price					Power and REC Prices				Emission Prices			
Year	Henry Hub Natural Gas ($/MMBtu)	DOM Zone Delivered Natural Gas ($/MMBtu)	CAPP CSX: 12,500 1%S FOB ($/MMBtu)	No. 2 Oil ($/MMBtu)	1% No.6 Oil ($/MMBtu)	PJM-DOM On-Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	RTO Capacity Prices ($/kW-yr)	CSAPR SO_2 ($/ton)	CSAPR Ozone NO_x ($/ton)	CSAPR Annual NO_x ($/ton)	CO_2 ($/ton)
2018	2.85	2.86	2.52	14.36	9.12	42.25	30.55	5.25	58.12	2.56	150.00	2.56	0.00
2019	2.87	2.87	2.42	13.73	8.61	38.33	29.11	5.25	46.35	2.65	192.19	2.67	0.00
2020	3.31	3.24	2.34	13.36	8.46	37.16	29.76	5.03	31.50	2.90	604.96	3.08	0.00
2021	3.64	3.49	2.33	14.14	8.91	35.97	29.90	4.87	30.63	3.08	867.79	3.36	0.00
2022	3.78	3.54	2.39	15.52	9.88	36.53	30.28	5.19	35.57	3.14	925.09	3.43	0.00
2023	3.91	3.66	2.45	16.53	10.58	37.69	31.29	5.53	40.42	3.20	985.90	3.49	0.00
2024	4.05	3.66	2.51	17.18	11.02	37.70	31.39	5.89	45.43	3.26	1,050.72	3.56	0.00
2025	4.20	3.78	2.57	17.98	11.57	38.96	32.33	6.28	50.62	3.32	1,119.63	3.62	0.00
2026	4.33	4.00	2.63	18.68	12.05	40.78	34.02	6.69	55.98	3.38	913.36	3.69	0.35
2027	4.47	4.19	2.69	19.34	12.50	42.24	35.45	7.13	61.54	3.45	745.32	3.76	0.56
2028	4.61	4.21	2.76	19.98	12.93	42.32	35.53	7.60	67.30	3.51	608.48	3.83	1.83
2029	4.75	4.45	2.83	20.73	13.44	44.52	37.35	8.10	74.11	3.58	496.95	3.91	2.16
2030	4.90	4.51	2.89	21.35	13.86	44.62	37.67	8.63	81.74	3.65	3.98	3.98	3.70
2031	5.03	4.62	2.96	22.21	14.45	45.88	38.90	9.20	86.66	3.72	4.06	4.06	5.04
2032	5.16	4.66	3.02	23.09	15.06	46.45	39.61	9.80	89.58	3.79	4.13	4.13	6.53
2033	5.30	5.01	3.09	24.02	15.70	50.25	42.91	10.44	92.57	3.86	4.21	4.21	8.20

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices for all commodities except capacity prices. 2021 and beyond are forecast prices. Capacity prices reflect PJM RPM auction clearing prices through delivery year 2020/2021, forecast thereafter. CO_2 prices reflect the price in Virginia. Refer to Sections 4.4.1 and 4.4.2 for additional details.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Natural Gas

Year	DOM Zone Natural Gas Price (Nominal $/MMBtu)		
	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.86	2.86	2.86
2019	2.87	2.87	2.87
2020	3.24	3.33	3.33
2021	3.49	3.61	3.61
2022	3.54	3.65	3.65
2023	3.66	3.72	3.76
2024	3.66	3.70	3.76
2025	3.78	3.81	3.87
2026	4.00	4.01	4.06
2027	4.19	4.17	4.21
2028	4.21	3.99	4.19
2029	4.45	4.23	4.39
2030	4.51	4.17	4.40
2031	4.62	4.24	4.48
2032	4.66	4.16	4.47
2033	5.01	4.58	4.79

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Natural Gas

Year	Henry Hub Natural Gas Price (Nominal $/MMBtu)		
	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.85	2.85	2.85
2019	2.87	2.88	2.88
2020	3.31	3.40	3.39
2021	3.64	3.76	3.76
2022	3.78	3.89	3.89
2023	3.91	4.02	4.02
2024	4.05	4.15	4.15
2025	4.20	4.29	4.29
2026	4.33	4.38	4.38
2027	4.47	4.48	4.48
2028	4.61	4.59	4.59
2029	4.75	4.69	4.69
2030	4.90	4.80	4.80
2031	5.03	4.89	4.89
2032	5.16	4.99	4.99
2033	5.30	5.08	5.09

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Coal: FOB

	CAPP 12,500 1% S Coal (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.52	2.52	2.52
2019	2.42	2.42	2.42
2020	2.34	2.35	2.35
2021	2.33	2.34	2.34
2022	2.39	2.40	2.40
2023	2.45	2.46	2.46
2024	2.51	2.52	2.52
2025	2.57	2.58	2.58
2026	2.63	2.64	2.64
2027	2.69	2.70	2.70
2028	2.76	2.76	2.76
2029	2.83	2.83	2.83
2030	2.89	2.89	2.89
2031	2.96	2.96	2.96
2032	3.02	3.03	3.03
2033	3.09	3.09	3.09

Note: The 2018 – 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Oil

	No. 2 Oil (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	14.36	14.36	14.36
2019	13.73	13.73	13.73
2020	13.36	13.36	13.36
2021	14.14	14.14	14.14
2022	15.52	15.52	15.52
2023	16.53	16.53	16.53
2024	17.18	17.18	17.18
2025	17.98	17.98	17.98
2026	18.68	18.68	18.68
2027	19.34	19.34	19.34
2028	19.98	19.98	19.98
2029	20.73	20.73	20.73
2030	21.35	21.35	21.35
2031	22.21	22.21	22.21
2032	23.09	23.09	23.09
2033	24.02	24.02	24.02

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Oil

	1% No. 6 Oil (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	9.12	9.12	9.12
2019	8.61	8.61	8.61
2020	8.46	8.46	8.46
2021	8.91	8.90	8.90
2022	9.88	9.88	9.88
2023	10.58	10.58	10.58
2024	11.02	11.02	11.02
2025	11.57	11.57	11.57
2026	12.05	12.05	12.05
2027	12.50	12.50	12.50
2028	12.93	12.93	12.93
2029	13.44	13.44	13.44
2030	13.86	13.86	13.86
2031	14.45	14.45	14.45
2032	15.06	15.06	15.06
2033	15.70	15.70	15.70

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

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ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; On-Peak Power Price

	Dom Zone Power On Peak (Nominal $/MWh)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	42.25	42.25	42.25
2019	38.33	38.41	38.38
2020	37.16	38.33	38.05
2021	35.97	37.52	37.07
2022	36.53	38.06	37.54
2023	37.69	38.73	38.56
2024	37.70	38.65	38.45
2025	38.96	39.90	39.56
2026	40.78	41.76	40.92
2027	42.24	43.20	41.90
2028	42.32	41.42	41.38
2029	44.52	44.08	43.09
2030	44.62	43.34	42.67
2031	45.88	43.86	43.16
2032	46.45	42.63	42.91
2033	50.25	46.88	45.87

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Off-Peak Power Price

	Dom Zone Power Off Peak (Nominal $/MWh)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	30.55	30.55	30.55
2019	29.11	29.16	29.14
2020	29.76	30.62	30.43
2021	29.90	31.11	30.78
2022	30.28	31.50	31.13
2023	31.29	32.19	32.09
2024	31.39	32.23	32.13
2025	32.33	33.23	33.01
2026	34.02	34.89	34.29
2027	35.45	36.24	35.28
2028	35.53	34.74	34.82
2029	37.35	36.83	36.18
2030	37.67	36.38	36.01
2031	38.90	36.88	36.49
2032	39.61	36.04	36.40
2033	42.91	39.55	38.87

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; PJM Tier 1 Renewable Energy Certificates

	PJM Tier 1 REC Prices (Nominal $/MWh)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	5.25	5.25	5.25
2019	5.25	5.32	5.33
2020	5.03	5.97	6.03
2021	4.87	6.37	6.46
2022	5.19	6.79	6.88
2023	5.53	7.23	7.34
2024	5.89	7.70	7.82
2025	6.28	8.21	8.33
2026	6.69	8.75	8.87
2027	7.13	9.32	9.46
2028	7.60	9.94	10.08
2029	8.10	10.59	10.75
2030	8.63	11.29	11.45
2031	9.20	12.03	12.20
2032	9.80	12.81	13.00
2033	10.44	13.65	13.85

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; PJM RTO Capacity

Year	RTO Capacity Prices (Nominal $/kW-yr)		
	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	58.12	58.12	58.12
2019	46.35	46.35	46.35
2020	31.50	31.50	31.50
2021	30.63	30.78	30.83
2022	35.57	35.99	36.11
2023	40.42	41.11	41.31
2024	45.43	46.41	46.69
2025	50.62	51.89	52.25
2026	55.98	57.56	58.01
2027	61.54	63.44	63.98
2028	67.30	69.53	70.17
2029	74.11	76.14	76.84
2030	81.74	83.18	83.93
2031	86.66	87.75	88.47
2032	89.58	90.51	91.13
2033	92.57	93.34	93.86

Note: PJM RPM auction clearing prices through delivery year 2020/21, forecast thereafter.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; SO_2 Emission Allowances

Year	CSAPR SO_2 Prices (Nominal $/ton)		
	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.56	2.56	2.56
2019	2.65	2.65	2.65
2020	2.90	2.90	2.90
2021	3.08	3.08	3.08
2022	3.14	3.14	3.14
2023	3.20	3.20	3.20
2024	3.26	3.26	3.26
2025	3.32	3.32	3.32
2026	3.38	3.38	3.38
2027	3.45	3.45	3.45
2028	3.51	3.51	3.51
2029	3.58	3.58	3.58
2030	3.65	3.65	3.65
2031	3.72	3.72	3.72
2032	3.79	3.79	3.79
2033	3.86	3.86	3.86

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; NO_x Emission Allowances

	CSAPR Ozone NOx Prices (Nominal $/ton)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	150.00	150.00	150.00
2019	192.19	192.19	192.19
2020	604.96	604.96	604.96
2021	867.79	867.79	867.79
2022	925.09	925.09	925.09
2023	985.90	985.90	985.90
2024	1,050.72	1,050.72	1,050.72
2025	1,119.63	1,119.63	1,119.63
2026	913.36	913.36	913.36
2027	745.32	745.32	745.32
2028	608.48	608.48	608.48
2029	496.95	496.95	496.95
2030	3.98	3.98	3.98
2031	4.06	4.06	4.06
2032	4.13	4.13	4.13
2033	4.21	4.21	4.21

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; NO_x Emission Allowances

	CSAPR Annual NOx Prices (Nominal $/ton)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	6.14	0.00
2021	0.00	6.47	0.00
2022	0.00	6.80	0.00
2023	0.00	7.14	0.00
2024	0.00	7.50	0.00
2025	0.00	7.87	0.00
2026	0.35	8.28	0.00
2027	0.56	8.72	0.00
2028	1.83	9.18	0.00
2029	2.16	9.66	0.00
2030	3.70	10.17	0.00
2031	5.04	10.71	0.00
2032	6.53	11.29	0.00
2033	8.20	11.89	0.00

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; CO_2

Year	CO_2 Prices (Nominal $/ton)		
	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	6.14	0.00
2021	0.00	6.47	0.00
2022	0.00	6.80	0.00
2023	0.00	7.14	0.00
2024	0.00	7.50	0.00
2025	0.00	7.87	0.00
2026	0.35	8.28	0.00
2027	0.56	8.72	0.00
2028	1.83	9.18	0.00
2029	2.16	9.66	0.00
2030	3.70	10.17	0.00
2031	5.04	10.71	0.00
2032	6.53	11.29	0.00
2033	8.20	11.89	0.00

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

Appendix 4B – Delivered Fuel Data for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company — Schedule 18

FUEL DATA

	2015 (ACTUAL)	2016	2017	2018	2019 (PROJECTED)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. Delivered Fuel Price ($/mmBtu)(1)																			
a. Nuclear	0.67	0.70	0.70	0.64	0.64	0.63	0.61	0.61	0.60	0.61	0.61	0.63	0.64	0.65	0.66	0.66	0.67	0.68	0.69
b. Coal	2.87	2.61	2.70	2.10	2.18	2.24	2.30	2.36	2.42	2.47	2.53	2.59	2.66	2.72	2.79	2.85	2.92	2.99	3.06
c. Heavy Fuel Oil	7.78	7.28	6.34	6.60	7.04	8.23	9.06	9.58	10.04	10.43	10.80	11.21	11.69	12.14	12.58	13.09	13.52	14.11	14.73
d. Light Fuel Oil(2)	14.54	10.63	11.73	11.35	11.97	13.22	14.26	15.02	15.69	16.27	16.81	17.42	18.12	18.78	19.43	20.18	20.81	21.68	22.57
e. Natural Gas	4.11	2.37	3.50	3.28	3.30	3.41	3.49	3.54	3.66	3.68	3.77	4.00	4.19	4.21	4.45	4.51	4.62	4.66	5.01
f. Renewable(3)	3.16	3.17	3.00	2.44	2.79	2.83	2.87	2.92	2.93	3.00	3.03	3.07	3.17	3.22	3.30	3.39	3.47	3.57	3.67
II. Primary Fuel Expenses (cents/kWh)(4)																			
a. Nuclear	0.69	0.72	0.72	0.68	0.68	0.66	0.64	0.63	0.63	0.64	0.64	0.66	0.67	0.67	0.68	0.69	0.70	0.71	0.72
b. Coal	3.13	3.09	2.88	2.46	2.35	2.36	2.40	2.47	2.54	2.60	2.68	2.75	2.80	2.86	2.93	3.00	3.08	3.16	3.24
c. Heavy Fuel Oil	12.25	8.56	7.60	10.10	9.59	9.36	9.43	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Light Fuel Oil(2)	11.62	6.80	16.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
e. Natural Gas	3.03	2.18	2.64	2.01	2.00	2.08	2.09	2.08	2.09	2.05	2.10	2.37	2.48	2.53	2.61	2.70	2.77	2.85	2.94
f. Renewable(3)	4.93	4.64	4.25	3.05	3.11	3.16	3.21	3.25	3.28	3.38	3.39	3.45	3.58	3.62	3.68	3.82	3.91	4.02	4.12
g. NUG(5)	3.21	2.98	5.28	6.99	2.24	2.86	2.92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
i. Economy Energy Purchases(6)	4.56	15.62	3.36	2.50	2.52	2.50	2.46	2.50	2.56	2.56	2.71	2.93	2.89	2.98	3.17	3.21	3.38	3.56	3.84
j. Capacity Purchases ($/kW-Year)	48.12	49.21	52.64	58.12	46.35	31.50	30.78	35.99	41.11	46.41	51.89	57.56	63.44	69.53	76.14	83.18	87.75	90.51	93.34

(1) Delivered fuel price for Central Appalachian ("CAPP") CSX (12,500, 1% FOB), No. 2 Oil, No. 6 Oil, DOM Zone Delivered Natural Gas are used to represent Coal, Heavy Fuel, Light Fuel Oil and Natural Gas respectively.

(2) Light fuel oil is used for reliability only at dual-fuel facilities.

(3) Reflects biomass units only.

(4) Primary Fuel Expenses for Nuclear, Coal, Heavy Fuel Oil, Natural Gas and Renewable are based on North Anna 1, Chesterfield 6, Yorktown 3, Possum Point 6, Pittsylvania, respectively.

(5) Average of NUGs Fuel Expenses.

(6) Average cost of Market Energy Purchases.

Appendix 5A - Tabular Results of Busbar

	Capacity Factor (%)										
$/kW-Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2X1 CC	$ 197	$ 231	$ 266	$ 301	$ 336	$ 370	$ 405	$ 440	$ 475	$ 509	$ 544
1X1 CC	$ 257	$ 293	$ 330	$ 367	$ 403	$ 440	$ 476	$ 513	$ 550	$ 586	$ 623
CT	$ 58	$ 123	$ 188	$ 252	$ 317	$ 382	$ 447	$ 512	$ 576	$ 641	$ 706
Aero CT	$ 198	$ 249	$ 301	$ 352	$ 403	$ 454	$ 506	$ 557	$ 608	$ 659	$ 711
Solar & Aero CT	$ 309	$ 349	$ 388	$ 427	$ 467	$ 506	$ 545	$ 584	$ 624	$ 663	$ 702
Nuclear	$ 1,048	$ 1,058	$ 1,068	$ 1,078	$ 1,088	$ 1,098	$ 1,108	$ 1,118	$ 1,128	$ 1,139	$ 1,149
Biomass	$ 968	$ 1,045	$ 1,122	$ 1,198	$ 1,275	$ 1,352	$ 1,429	$ 1,505	$ 1,582	$ 1,659	$ 1,735
Fuel Cell	$ 1,313	$ 1,341	$ 1,370	$ 1,399	$ 1,427	$ 1,456	$ 1,485	$ 1,514	$ 1,542	$ 1,571	$ 1,600
SCPC w/ CCS	$ 636	$ 780	$ 925	$ 1,069	$ 1,213	$ 1,357	$ 1,502	$ 1,646	$ 1,790	$ 1,935	$ 2,079
IGCC w/ CCS	$ 1,282	$ 1,416	$ 1,549	$ 1,682	$ 1,815	$ 1,949	$ 2,082	$ 2,215	$ 2,349	$ 2,482	$ 2,615
Solar				$ 103							
Onshore Wind					$ 269						
Offshore Wind					$ 443						
CVOW					$ 2,810						

(1) CVOW and Offshore Wind both have a capacity factor of 42%.
(2) Onshore Wind has a capacity factor of 37%.
(3) Solar PV has a capacity factor of 26%.

Appendix 5B - Busbar Assumptions

Nominal $	Heat Rate MMBtu/MWh	Variable Cost[1] $/MWh	Fixed Cost[3] $/kW-Year	Book Life Years	2017 Real $[2] $/kW
2X1 CC	6.59	40	197	36	1,233
1X1 CC	6.63	42	257	36	1,668
CT	10.07	74	58	36	476
Aero CT	9.32	59	198	36	1,680
Solar & Aero CT	9.32	58	235	35 (Solar) / 36 (CT)	3,366
Nuclear	10.50	12	1,048	60	9,133
Biomass	13.00	88	968	40	6,698
Fuel Cell	8.54	33	1,313	15	5,880
SCPC w/ CCS	11.06	165	636	55	5,366
IGCC w/ CCS	10.88	152	1,282	40	10,839
Solar	-	(10)	128	35	1,436
Onshore Wind	-	(9)	301	25	2,112
Offshore Wind	-	(9)	476	30	4,021
CVOW	-	(9)	2,841	25	25,838

(1) Variable cost for biomass, solar, solar & aero, onshore wind, offshore wind, and CVOW includes value for RECs.
(2) Values in this column represent overnight installed costs.
(4) Fixed costs include investment tax credits and gas firm transportation expenses.

Appendix 5C – Planned Generation under Development

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

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[2]	MW Summer	MW Nameplate
Under Development[1]						
US-3 Solar 1	VA	Intermittent	Solar	2020	33	142
US-3 Solar 2	VA	Intermittent	Solar	2021	22	98
CVOW	VA	Intermittent	Wind	2021	2	12[3]
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

(1) Includes the additional resources under development in the Alternative Plans.

(2) Estimated Commercial Operation Date.

(3) Accounts for line losses.

Appendix 5D – Standard DSM Test Descriptions

Participant Test

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

Utility Cost Test

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

Total Resource Cost Test

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

Ratepayer Impact Measure Test

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

Appendix 5E – DSM Programs Energy Savings for Plan E: Federal CO_2 Program
(MWh)
(System-Level)

Company Name: Virginia Electric and Power Company

Schedule 12

Program Name	Date [2]	Life/ Duration [3]	Size kW [4]	ACTUAL - MWh 2015	2016	2017	(PROJECTED - MWh) 2018	2019	2020	2021	2022
Air Conditioner Cycling Program	2010	2033	91,285	0	0	0	0	0	0	0	0
Sub-total			91,285	0	0	0	0	0	0	0	0
Non-Residential Distributed Generation Program	2010	2033	10,743				1	1,010	0	1	2
Standby Generation (Pricing Tariffs) [5]	1987	2033	1,482	342	274	139	139	139	139	139	139
Sub-total			12,226	342	274	139	140	1,149	139	140	141
Residential Low Income Program	2010	2029	0	6,536	8,882	8,882	10,442	10,442	10,442	10,442	10,442
Residential Lighting Program	2010	2021	0	228,892	228,892	228,892	206,284	178,936	111,858	36,201	0
Commercial Lighting Program	2010	2024	0	73,417	73,417	73,417	82,457	82,457	75,328	45,025	11,789
Commercial HVAC Upgrade	2010	2027	0	5,936	5,936	5,936	5,851	5,851	6,867	5,851	5,851
Non-Residential Energy Audit Program	2010	2023	0	33,297	35,823	40,510	38,155	38,143	32,687	18,938	4,814
Non-Residential Duct Testing and Sealing Program	2012	2033	11,013	36,674	68,854	71,873	67,720	67,720	67,720	67,720	67,720
Residential Bundle Program	2010 [6]	2033	142	45,264	59,890	67,619	70,043	67,240	61,277	55,858	52,912
Residential Home Energy Check-Up Program	2012	2027	0	19,706	28,450	33,361	34,584	34,584	34,584	34,584	34,574
Residential Duct Sealing Program	2012	2033	142	451	759	895	947	947	947	947	947
Residential Heat Pump Tune Up Program	2012	2021	0	13,140	17,658	19,775	17,121	14,318	8,354	2,934	0
Residential Heat Pump Upgrade Program	2012	2031	0	11,968	13,024	13,769	17,391	17,391	17,391	17,391	17,391
Non-Residential Window Film Program	2014	2033	44,858	2,765	3,818	4,426	25,860	39,033	40,989	43,005	45,051
Non-Residential Lighting Systems & Controls Program	2014	2033	34,823	21,142	63,983	116,051	159,339	193,288	196,635	204,087	209,646
Non-Residential Heating and Cooling Efficiency Program	2014	2033	50,508	4,986	13,607	22,348	70,367	108,956	113,869	118,852	123,935
Income and Age Qualifying Home Improvement Program	2015	2033	2,880	112	1,991	4,915	6,156	7,677	9,430	11,182	12,935
Residential Appliance Recycling Program	2015	2024	0	659	5,489	10,471	11,492	11,492	11,492	11,492	11,492
Small Business Improvement Program	2016	2033	21,786	0	68	7,442	17,389	33,401	52,153	61,749	63,212
Residential Retail LED Lighting Program (NC only)	2017	2033	922	0	0	512	4,087	6,557	6,557	6,557	6,557
Non-Residential Prescriptive Program	2017	2033	36,119	0	0	0	29,124	81,731	134,339	186,948	213,532
Sub-total			202,049	459,860	556,048	680,292	804,565	928,926	932,643	881,905	839,669
Total Demand-Side Management			305,560	460,002	556,322	680,431	804,705	930,075	932,782	882,045	839,810

Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0
Sub-total	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Distributed Generation Program	6	3	1	184	1	1	1	1	2	1	0
Standby Generation (Pricing Tariffs) [5]	139	139	139	139	139	139	139	139	139	139	139
Sub-total	145	142	140	323	140	140	140	140	140	140	139
Residential Low Income Program	10,442	9,833	7,516	4,814	2,963	1,323	257	0	0	0	0
Residential Lighting Program	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	705	321	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	5,851	5,867	5,150	3,083	841	0	0	0	0	0	0
Non-Residential Energy Audit Program	1,636	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720
Residential Bundle Program	52,377	45,275	34,034	24,199	18,793	16,800	13,840	9,802	4,880	671	557
Residential Home Energy Check-Up Program	34,038	26,937	15,696	5,861	482	0	0	0	0	0	0
Residential Duct Sealing Program	947	947	947	947	947	947	947	946	932	871	557
Residential Heat Pump Tune Up Program	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	17,391	17,391	17,391	17,391	17,353	15,853	12,893	8,856	3,946	0	0
Non-Residential Window Film Program	46,110	46,460	46,805	47,138	47,463	47,778	48,083	48,384	48,681	48,975	49,270
Non-Residential Lighting Systems & Controls Program	212,684	213,495	214,311	215,099	215,860	216,601	217,326	218,044	218,753	219,453	220,155
Non-Residential Heating and Cooling Efficiency Program	126,804	127,705	128,590	129,445	130,270	131,074	131,863	132,639	133,406	134,168	134,928
Income and Age Qualifying Home Improvement Program	13,834	13,923	14,010	14,092	14,171	14,247	14,321	14,393	14,464	14,534	14,604
Residential Appliance Recycling Program	10,068	5,433	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	64,147	64,653	65,149	65,628	66,091	66,541	66,984	67,717	72,385	75,775	78,202
Residential Retail LED Lighting Program (NC only)	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557
Non-Residential Prescriptive Program	216,827	218,822	220,780	222,671	224,498	226,276	228,021	229,739	231,439	233,121	234,803
Sub-total	835,740	826,063	810,621	800,448	795,227	794,918	794,773	794,994	798,268	801,174	804,797
Total Demand-Side Management	835,885	826,205	810,762	800,771	795,367	795,058	794,913	795,134	798,407	801,314	804,936

(1) The Program types have been categorized by the Virginia definitions of peak shaving, energy efficiency, and demand response.

(2) Implementation date.

(3) State expected life of facility or duration of purchase contract. The Company used Program Life (Years).

(4) The MWs reflected as of 2033.

(5) Reductions available during on-peak hours.

(6) Residential Bundle is comprised of the Residential Home Energy Check-Up Program, Residential Duct Testing & Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program.

Confidential Information Redacted
Appendix 5F – Cost Estimates for Nuclear License Extensions

	Capital Cost
North Anna Units 1 & 2	[redacted]
Surry Units 1 & 2	[redacted]

Appendix 6A – Renewable Resources for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

RENEWABLE RESOURCE GENERATION (GWh)

Schedule 11

						(ACTUAL)				(PROJECTED)														
Resource Type[1]	Unit Name	C.O.D.[2]	Build/Purchase/ Convert[3]	Life/ Duration[4]	Size MW[5]	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Hydro																								
	Gaston Hydro	Feb-63	Build	60	220	318	408	271	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258
	North Anna Hydro	Dec-87	Build	60	1	4	4	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	Sep-55	Build	60	95	288	355	211	253	253	254	253	253	253	254	253	253	253	254	253	253	253	254	253
Sub-total					318	617	775	484	513	513	514	513	513	513	514	513	513	513	514	513	513	513	514	513
Solar																								
	Solar Partnership Program	2013-2017	Build	20	7	2.3	7	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Existing NC Solar NUGs	2014-2022	Purchase	20	660	161	441	634	1,201	1,380	1,450	1,438	1,431	1,424	1,421	1,410	1,403	1,398	1,383	1,382	1,375	1,368	1,355	1,344
	Existing VA Solar NUGs	2016-2017	Purchase	20	100	-	-	-	45	62	62	62	61	61	61	60	60	60	59	59	59	59	58	58
	US-3 Solar 1	2020	Build	35	142				-	-	355	352	351	349	348	345	344	342	341	339	337	335	334	332
	US-3 Solar 2	2021	Build	35	98				-	-	-	233	232	231	230	228	227	226	226	224	223	222	221	219
	Whitehouse Solar	Dec-2016	Build	35	20	-	1	35	44	43	43	43	43	43	42	42	42	42	42	41	41	41	41	40
	Scott Solar	Dec-2016	Build	35	17	-	1	31	37	37	37	37	37	37	36	36	36	36	36	35	35	35	35	35
	Woodland Solar	Dec-2016	Build	35	19	-	1	30	43	42	42	42	42	41	41	41	41	41	41	40	40	40	40	39
	Generic Solar PV	2019-2032	Build	35	5,760	-	-	-	-	-	715	1,604	2,673	3,742	4,647	5,702	6,771	7,841	8,936	9,801	10,514	10,692	11,795	12,830
Sub-total					6,823	164	449.8	737	1,378	1,574	2,713	3,820	4,878	5,936	6,835	7,874	8,933	9,991	11,081	-11,930	12,632	12,800	13,888	14,907
Biomass	Unit Name																							
	Pittsylvania	Jun-94	Purchase	60	83	267	146	109	394	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Virginia City Hybrid Energy Center [6]	Apr-12	Build	60	61	100	236	204	240	259	332	339	353	343	316	327	351	342	321	318	309	301	290	297
	Altavista	Feb-92	Convert	30	51	269	283	278	336	336	335	329	334	51	52	58	71	78	73	81	81	92	98	131
	Southampton	Mar-92	Convert	30	51	290	30	28	272	235	247	225	242	27	28	29	30	37	31	39	37	43	48	71
	Hopewell	Jul-92	Convert	30	51	263	306	295	307	290	303	292	299	41	39	39	45	55	51	55	61	72	73	100
Sub-total					297	1,189	1,000	912	1,551	1,120	1,217	1,184	1,227	483	435	452	498	512	476	494	488	509	509	599
Wind																								
	CVOW	Jan-21	Build	20	12	-	-		-	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44
Sub-total					12	-	-		-	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44
Total Renewables					7,450	1,969	2,225	2,133	3,441	3,207	4,444	5,561	6,662	6,956	7,829	8,883	9,987	11,059	12,115	12,980	13,677	13,865	14,955	16,062

(1) Per definition of § 56-576 of the Code of Virginia.
(2) Commercial Operation Date.
(3) Company built, purchased or converted.
(4) Expected life of facility or duration of purchase contract.
(5) Net Summer Capacity for Biomass and Hydro, Nameplate for Solar and Wind.
(6) Dual fired coal & biomass reaching 61 MW in 2023.

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Appendix 6B – Potential Supply-Side Resources for Plan E: Federal CO_2 Program

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

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Unit Type	Primary Fuel Type	C.O.D.[(1)]	MW Summer [(2)]	MW Nameplate
Solar 2020	Intermittent	Solar	2020	73	320
US-3 Solar 1	Intermittent	Solar	2020	33	142
Solar 2021	Intermittent	Solar	2021	91	400
US-3 Solar 2	Intermittent	Solar	2021	22	98
CVOW	Intermittent	Wind	2021	2	12
Solar 2022	Intermittent	Solar	2022	110	480
Generic CT	Peak	Natural Gas	2022	458	458
Solar 2023	Intermittent	Solar	2023	110	480
Generic CT	Peak	Natural Gas	2023	458	458
Solar 2024	Intermittent	Solar	2024	91	400
Generic CT	Peak	Natural Gas	2024	458	458
Solar 2025	Intermittent	Solar	2025	110	480
Generic CT	Peak	Natural Gas	2025	458	458
Solar 2026	Intermittent	Solar	2026	110	480
Generic CT	Peak	Natural Gas	2026	458	458
Solar 2027	Intermittent	Solar	2027	110	480
Solar 2028	Intermittent	Solar	2028	110	480
Solar 2029	Intermittent	Solar	2029	91	400
Generic CT	Peak	Natural Gas	2029	458	458
Solar 2030	Intermittent	Solar	2030	73	320
Generic CT	Peak	Natural Gas	2030	458	458
Solar 2031	Intermittent	Solar	2031	18	80
Generic CT	Peak	Natural Gas	2031	458	458
Solar 2032	Intermittent	Solar	2032	110	480
Solar 2033	Intermittent	Solar	2033	110	480

(1) Estimated Commercial Operation Date.
(2) Summer MWs represent the firm capacity of each unit.

Confidential Information Redacted

Appendix 6C – Summer Capacity Position for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

UTILITY CAPACITY POSITION (MW)

Schedule 16

	(ACTUAL)			(PROJECTED)															
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Existing Capacity																			
Conventional	18,928	18,933	18,958	17,736	17,683	17,609	18,745	15,948	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945
Renewable	553	553	553	529	523	529	535	542	545	545	545	545	545	545	545	544	544	544	544
Total Existing Capacity	19,481	19,486	19,509	18,265	18,188	18,138	17,280	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490
Generation Under Construction																			
Conventional	-	-	-	-	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Construction Capacity	-	-	-	-	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	33	58	58	58	55	55	55	55	54	54	54	54	53	53
Total Planned Development Capacity	-	-	-	-	-	33	58	58	58	55	55	55	55	54	54	54	54	53	53
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	-	458	918	1,374	1,832	2,290	2,290	2,290	2,748	3,206	3,664	3,664	3,664
Renewable	-	-	-	-	-	73	163	272	361	472	581	689	796	907	998	1,070	1,089	1,198	1,306
Total Potential New Capacity	-	-	-	-	-	73	163	730	1,297	1,846	2,413	2,979	3,086	3,197	3,746	4,276	4,753	4,862	4,970
Other (NUG)	1,775	1,252	238	348	368	372	372	153	152	152	151	150	149	149	148	147	148	145	144
Unforced Availability	-	-																	
Net Generation Capacity	21,258	20,738	19,747	18,611	20,137	20,201	19,458	19,014	19,580	20,128	20,694	21,259	21,367	21,475	22,023	22,552	23,028	23,134	23,242
Existing DSM Reductions																			
Demand Response	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Conservation/Efficiency	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions(1)	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Approved DSM Reductions																			
Demand Response(4)	81	103	70	99	100	100	101	101	102	102	102	102	102	102	102	102	102	102	102
Conservation/Efficiency(2)(4)	72	93	109	154	183	202	203	202	204	202	200	198	198	198	198	198	200	201	202
Total Approved DSM Reductions	153	196	179	254	283	302	303	304	306	304	302	300	300	300	300	300	302	303	304
Proposed DSM Reductions																			
Demand Response(4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency(2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Proposed DSM Reductions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Demand-Side Reductions(1)	155	198	181	255	285	304	305	305	307	305	303	302	301	301	301	302	303	305	306
Net Generation & Demand-side	21,411	20,936	19,927	18,866	20,431	20,505	19,761	19,318	19,887	20,433	20,997	21,561	21,668	21,777	22,324	22,854	23,331	23,439	23,548
Capacity Sale(3)	[redacted]								-	-	-	-	-	-	-	-	-	-	-
Capacity Purchase(3)									1,100	1,000	800	800	800	900	700	500	300	400	400
Capacity Adjustment(3)									-	-	-	-	-	-	-	-	-	-	-
Capacity Requirement or PJM Capacity Obligation									20,965	21,485	21,847	22,214	22,457	22,674	23,005	23,389	23,652	23,839	24,024
Net Utility Capacity Position									(1,078)	(1,052)	(850)	(653)	(789)	(896)	(681)	(535)	(321)	(400)	(476)

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

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

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

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

Appendix 6D – Construction Forecast for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

Schedule 17

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. New Traditional Generating Facilities																
a. Construction Expenditures (non-AFUDC)	60,230	266,162	588,571	714,021	769,826	688,425	611,920	495,641	242,863	338,722	360,618	350,887	208,672	131,133	238,489	296,445
b. AFUDC	153	646	1,962	4,005	5,465	6,843	7,859	8,498	8,522	9,439	10,671	10,808	10,577	4,093	4,721	1,768
c. Annual Total	60,383	266,807	590,533	718,026	775,091	695,269	619,780	504,140	251,385	348,162	371,289	361,695	219,249	135,226	243,210	298,213
d. Cumulative Total	60,383	327,190	917,723	1,635,749	2,410,840	3,106,109	3,725,889	4,230,028	4,481,413	4,829,575	5,200,864	5,562,559	5,781,809	5,917,035	6,160,245	6,458,458
II. New Renewable Generating Facilities																
a. Construction Expenditures (non-AFUDC)	127,903	551,633	748,049	718,976	710,554	594,736	717,332	753,926	768,913	773,491	657,151	525,641	196,119	848,438	890,640	896,006
b. AFUDC	247	1,556	2,232	1,604	1,589	1,323	1,600	1,682	1,715	1,729	1,468	1,182	418	1,896	1,987	2,002
c. Annual Total	128,150	553,190	750,281	720,580	712,142	596,059	718,932	755,608	770,628	775,220	658,619	526,823	196,537	850,334	892,627	898,009
d. Cumulative Total	128,150	681,339	1,431,620	2,152,200	2,864,342	3,460,401	4,179,333	4,934,941	5,705,569	6,480,789	7,139,408	7,666,231	7,862,767	8,713,102	9,605,728	10,503,737
III. Other Facilities																
a. Transmission	777,736	911,890	784,451	784,738	826,874	857,241	836,003	851,548	854,887	847,479	851,305	851,345	851,376	851,342	851,354	851,357
b. Distribution	727,300	770,288	847,930	839,988	852,572	864,130	882,632	888,879	888,080	885,864	886,941	711,941	711,941	711,941	711,941	711,941
c. Energy Conservation & DR																
d. Other																
e. AFUDC	29,130	42,510	36,549	36,262	38,626	42,759	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000
f. Annual Total	1,534,166	1,724,688	1,668,930	1,660,988	1,718,072	1,764,130	1,757,636	1,777,427	1,781,966	1,772,343	1,777,248	1,602,286	1,602,317	1,602,283	1,602,295	1,602,298
g. Cumulative Total	1,534,166	3,258,854	4,927,785	6,588,773	8,306,845	10,070,975	11,828,611	13,606,038	15,388,004	17,160,347	18,937,593	20,539,879	22,142,196	23,744,479	25,346,774	26,949,072
IV. Total Construction Expenditures																
a. Annual	1,722,698	2,544,685	3,009,744	3,099,595	3,205,305	3,055,457	3,096,348	3,037,174	2,803,980	2,895,725	2,807,153	2,490,604	2,018,103	2,587,843	2,738,132	2,798,520
b. Cumulative	1,722,698	4,267,383	7,277,128	10,376,722	13,582,028	16,637,485	19,733,833	22,771,007	25,574,987	28,470,711	31,277,864	33,768,669	35,786,772	38,374,615	41,112,747	43,911,267
V. % 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

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Appendix 6E – Capacity Position for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company

POWER SUPPLY DATA

Schedule 4

	(ACTUAL)							(PROJECTED)											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. Capability (MW)																			
1. Summer																			
a. Installed Net Dependable Capacity[1]	19,481	19,486	19,509	18,265	19,771	19,828	19,085	18,861	19,428	19,976	20,543	21,109	21,218	21,326	21,875	22,405	22,881	22,990	23,098
b. Positive Interchange Commitments[2]	1,757	1,252	238	346	366	372	372	153	152	152	151	150	149	149	148	147	146	145	144
c. Capability in Cold Reserve/ Reserve Shutdown Status[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
e. Demand Response - Approved[5]	81	103	70	99	100	100	101	101	102	102	102	102	102	102	102	102	102	102	102
f. Demand Response - Future[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Capacity Sale[3]	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
h. Capacity Purchase[3]								1,300	1,100	1,000	800	600	800	900	700	500	300	400	400
i. Capacity Adjustment[3]								-	-	-	-	-	-	-	-	-	-	-	-
j. Total Net Summer Capability[4]								20,414	20,780	21,228	21,594	21,960	22,268	22,476	22,823	23,153	23,428	23,635	23,743
2. Winter																			
a. Installed Net Dependable Capacity[1]	-	-	-	19,452	21,052	21,059	20,239	20,039	20,632	21,206	21,798	22,390	22,499	22,608	23,182	23,738	24,240	24,348	24,457
b. Positive Interchange Commitments[2]	-	-	-	350	370	377	376	153	152	152	151	150	149	149	148	147	146	145	144
c. Capability in Cold Reserve/ Reserve Shutdown Status[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response[5]	5	4	5	8	8	9	9	10	11	11	11	11	11	11	11	11	11	11	11
e. Demand Response-Existing[6]	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
f. Total Net Winter Capability[4]	-	-	-	19,810	21,430	21,445	20,624	20,202	20,795	21,368	21,960	22,551	22,659	22,768	23,341	23,896	24,397	24,504	24,612

(1) Net Seasonal Capability.

(2) Includes firm commitments from existing Non-Utility Generation and estimated solar NUGs.

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

(4) Does not include Cold Reserve Capacity and Behind-the-Meter Generation MWs.

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

(6) Included in the winter capacity forecast.